STATE OF NEBRASKA

BEFORE THE

MUNICIPALITIES OF ALDA, GRAND ISLAND, KEARNEY
AND NORTH PLATTE
(NWE RATE AREA)

Application, Tariff, Testimony and Exhibits
of NorthWestern Corporation d/b/a
NorthWestern Energy

For Increased Natural Gas Rates

December 31, 2006 Test Year

BEFORE THE PUBLIC SERVICE COMMISSION OF NEBRASKA

In the Matter of NorthWestern Corporation d/b/a NorthWestern Energy, Seeking Approval of a Natural Gas Rate Increase.	)))	Application No. NG-___

APPLICATION FOR NATURAL GAS RATE INCREASE

Comes now NorthWestern Corporation, dba NorthWestern Energy ("NorthWestern" or "the Company"), pursuant to State Natural Gas Regulation Act, NEB.REV.STAT. § 66-1801 *et seq.* (2003) (the "Act") and the Rules and Regulations of the Nebraska Public Service Commission ("NPSC"), NEB.ADMIN.CODE, Title 291, Chapter 9, Natural Gas and Pipeline Rules and Regulations ("Chapter 9"), to adjust the rates for natural gas services provided to NorthWestern's customers located in the Nebraska communities of North Platte, Kearney, Grand Island, and Alda ("Affected Cities").

I. INTRODUCTION AND BACKGROUND OF NORTHWESTERN ENERGY

NorthWestern Public Services was incorporated in Delaware in November 1923 when utility holdings from both South Dakota and Nebraska were merged into one energy utility company. It has since generated and distributed electricity in South Dakota and distributed natural gas in South Dakota and Nebraska. NorthWestern Public Services became NorthWestern Corporation in 1998. In February 2002, NorthWestern acquired the electric and natural gas transmission and distribution business of the former Montana Power Company. NorthWestern Energy currently has approximately 1,350 employees within its three-state service territory.

NorthWestern's presence in Nebraska has evolved since its inception in 1923. Until the late 1930s, NorthWestern was an electric and gas utility in Nebraska. With the advent of a public power system in Nebraska, NorthWestern sold its electric utility services to local public power districts and by the early 1940s, had transformed its Nebraska utility business to solely natural gas. As of today, NorthWestern provides natural gas distribution services to the Affected Cities, serving approximately 41,300 customers. NorthWestern's Nebraska employees total 39 with area offices in North Platte, Grand Island and Kearney.

II. CONTACT INFORMATION

Communications regarding this Application should be addressed to the following:

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III. RATIONALE FOR RATE ADJUSTMENT AND RATE STRUCTURE

NorthWestern last negotiated a natural gas rate adjustment with its Nebraska communities in 1999 using 1998 test year data. The 1999 natural gas rate adjustment occurred prior to the NPSC gaining regulatory authority over jurisdictional natural gas utilities in 2003 with passage of the Act.

In Nebraska, NorthWestern uses only one rate area for the four Affected Cities it serves. Although NEB.REV.STAT. §66-1838(10)(b) allows NorthWestern to seek interim rate recovery, NorthWestern does not intend to seek an interim natural gas rate adjustment as part of this Application.

The current Nebraska rate structure does not allow NorthWestern to adequately recover its cost of doing business. Since 1999, NorthWestern has experienced the same inflationary pressure that any other Nebraska enterprise or citizen has experienced. Costs associated with purchasing pipe, buying fuel for its vehicles, employee compensation and benefits, new federal government regulations regarding natural gas utility operations, as well as a host of other expenses have increased without any adjustment to NorthWestern's rate recovery mechanisms.

NorthWestern is also seeing the effect of decreased revenue generation from residential customers while its costs to do business continue to increase. As residential customers become more knowledgeable about energy efficiency, replace older heating equipment with more efficient models, or make the switch to electric heating, the basic costs of maintaining utility infrastructure remain while trying to recover those costs through decreased use of natural gas – directly impacting NorthWestern's rate recovery mechanism. This phenomenon is further highlighted when consideration is given to weather normalizing NorthWestern's rate revenues. For example, when weather normalizing rate revenues from 1998 to present day to reflect normal Heat Degree Days, there is a decrease of 7 million Therms in natural gas usage from 1998 to 2006. With effective internal control mechanisms, NorthWestern has been able to weather these rising costs with decreasing rate revenues but can no longer do so without being given the ability to have a fair and reasonable return on its Nebraska infrastructure investments.

With this Application for a natural gas rate adjustment, NorthWestern is able to demonstrate that it requires an additional $2,813,794 in rate recovery. This amounts to an overall increase of 5.48%. NorthWestern is seeking a rate of return on rate base of 8.98% and a return on equity of 11.25%. This compares to the 1999 negotiated return on rate base of 8.28% and a return on equity of 10.25%. When this request is broken into our residential customer base and commercial customer base it will equate to a proposed increase of 7.76% for our residential customers and 2.62% for our commercial accounts. NorthWestern's current debt to equity ratio stands at 48.54% to 51.46%.

IV. RULE 004 GENERAL RATE FILING REQUIREMENTS

In support of its Application, and pursuant to Rule 004 of Chapter 9 of the NPSC's Natural Gas and Pipeline Rules and Regulations, NorthWestern hereby submits the following information that can be found in the attachments submitted herewith, some of which are under separate cover and marked "CONFIDENTIAL" pursuant to the Motion for Protective Order filed concurrently with this Application:

- A description of the base year and test year.

- A financial summary showing aggregate amounts for rate base, operating expenses, and rate of return for the base year and test year, plus operating revenue calculated using natural gas rates currently in effect and as proposed.

- Rate-base schedules showing beginning and ending balances for the base year and test year of:
    - Utility plant and accumulated depreciation and amortization showing the balances by functional account totals;
    - Working capital, showing the manner in which it is calculated;
    - Other rate-base components; and
    - Allocated rate-base components showing the manner in which the components are calculated;

- Operating expense schedules for the base year and test year;

- Rate-of-return and cost-of-capital schedules showing:
    - Long-term debt, preferred stock, and common equity amounts, ratios, and percentage cost rates for the base year and test year; and

- Long-term debt, preferred stock, and common equity amounts at the beginning and end of the base year and test year; and

- Operating revenue schedules showing:
  - Number and classification of customers, volume of sales, and operating revenue by customer classes for the base year on an unadjusted basis; and

  Number and classification of customers, volume of sales, and operating revenue by customer classes for the test year on a normalized basis:
    - Using current rates; and
    - Using proposed rates.

V. MUNICIPAL AND CUSTOMER NOTIFICATION

In accordance with NEB.REV.STAT. § 66-1838, NorthWestern seeks to negotiate its natural gas rate adjustment directly with the four Affected Cities: Alda, Grand Island, Kearney and North Platte. Simultaneous with the filing of this Application with the NPSC, letters have been sent to each Affected City notifying each of the natural gas rate Application filing with the NPSC and NorthWestern's intention to negotiate directly with each of the Affected Cities. Included with the notification letters are copies of the Application in electronic format for each Affected City's use. If an Affected City wishes to receive paper copies of the Application for the natural gas rate increase, those will be provided upon request from the Affected City in accordance with NEB.REV.STAT § 66-1838(2). Notice of the filing of the Application is also being sent to each Nebraska customer as a bill insert for the June 2007 billing cycles. A copy of the customer bill insert is included with this Application and has been provided to the community leaders as a part of their formal notification. A media announcement of the Application is also being distributed in concurrence with the submittal to the NPSC. A copy of the media announcement has been provided with this Application to the NPSC and NorthWestern's notice of the filing to the Affected Cities.

Prior to formally filing with the NPSC, NorthWestern representatives met with the mayor or city administrator of each Affected City in April 2007 to discuss NorthWestern's intent to file an application seeking a natural gas rate adjustment in early June 2007. NorthWestern sought to inform its community leaders in advance of the Application being filed as part of its continued commitment to maintain open communications with its Affected Cities and customers.

VI. TARIFF CHANGES AND SUPPORTING DOCUMENTATION

In support of its Application, and pursuant to NEB.REV.STAT. § 66-1838, NorthWestern hereby submits proposed revisions to its tariff, implementing its proposed rate change and other changes requested in this Application. The revised sections of the tariff are attached hereto.

VII. TESTIMONY IN SUPPORT OF APPLICATION

In support of its Application, NorthWestern submits the attached pre-filed direct testimony and accompanying exhibits of the following individuals:

Mike Hanson, President and CEO	Company Policy
Kendall Kliewer, VP and Controller	Accounting – Known & Measurable
Paul Evans, Treasurer	Cost of Capital
Jeff Decker, Regulatory Specialist	Weather Normalization
Jeff Decker, Regulatory Specialist	Class Cost of Service

VIII. PROTECTIVE ORDER/AGREEMENT

NorthWestern further notifies the NPSC that concurrent with the filing of this Application it has filed a request for "Protective Order" as required under NPSC Rule 006 of Chapter 9 of the NPSC's Natural Gas and Pipeline Rules and Regulations to cover confidential information that will supplement its Application and to cover any confidential materials submitted in NorthWestern's workpapers, testimony, or exhibits that will be filed throughout the review and approval of its rate Application. *See* NEB. ADMIN. CODE, Title 291, Chapter 9, Rule 006.

IX. CONCLUSION

WHEREFORE, NorthWestern requests that the NPSC issue an order accepting and approving this Application for Rate Increase, including the proposed rate schedule included herewith.

Respectfully submitted,

KENDALL KLIEWER
Vice President and Controller
NorthWestern Corporation

STATE OF NEBRASKA
BEFORE THE
NEBRASKA PUBLIC SERVICE COMMISSION

STATE OF SOUTH DAKOTA	)	
	) SS	VERIFICATION
COUNTY OF MINNEHAHA	)	

KENDALL KLIEWER, being first duly sworn on oath, deposes and states that: (1) he is the Vice President and Controller of NorthWestern Corporation, dba NorthWestern Energy, and is authorized to make this Verification on behalf of such Company; and (2) he has read the foregoing Application and the information set forth therein is true to the best of his knowledge and belief.

Kendall Kliewer

Sworn and subscribed to before me
this 1st day of May, 2007

Nancy Thompson
Notary Public, South Dakota
My Commission Expires: 3/20/12

(Seal)

NANCY THOMPSON
SEAL NOTARY PUBLIC SOUTH DAKOTA SEAL

NorthWestern Energy

notice...

As part of NorthWestern Energy's continued commitment to keeping open communications with our customers, we would like to officially notify you that in June, NorthWestern Energy will be seeking a natural gas rate increase in Nebraska.

Our last request for a natural gas rate increase occurred in 1999. Through effective business management practices and watching the bottom line, NorthWestern has been able to hold down its costs of doing business for nearly a decade. However, the past few years have demonstrated that a rate increase is necessary for NorthWestern to continue providing the high level of services that you have come to expect.

There are many options available to participate in the natural gas rate review process. Find out how on the reverse side of this notice...

The rate case process is as such:

- Following notification to the Nebraska Public Service Commission (NE PSC) and the four communities we serve (North Platte, Kearney, Grand Island, and Alda), the communities have 60 days to accept our notice to negotiate directly with them. NorthWestern Energy then has 90 days from the date of the filing with the NE PSC to reach an agreement with these four communities.
- Once agreement is met, it is submitted to the NE PSC for their review and approval. If we are unable to reach agreement, the NE PSC takes over and has 210 days to complete its review.

You can view the actual rate case filing via the Internet on the NorthWestern Energy Web site and/or the NE PSC Web site:
www.northwesternenergy.com

www.psc.state.ne.us

A copy of the filing will also be made available at each of our office locations, where you can request a copy to look at in-person.

If you have any questions about your natural gas services or the proposed rate increase, please call our Customer Service number at: (800) 245-6977.

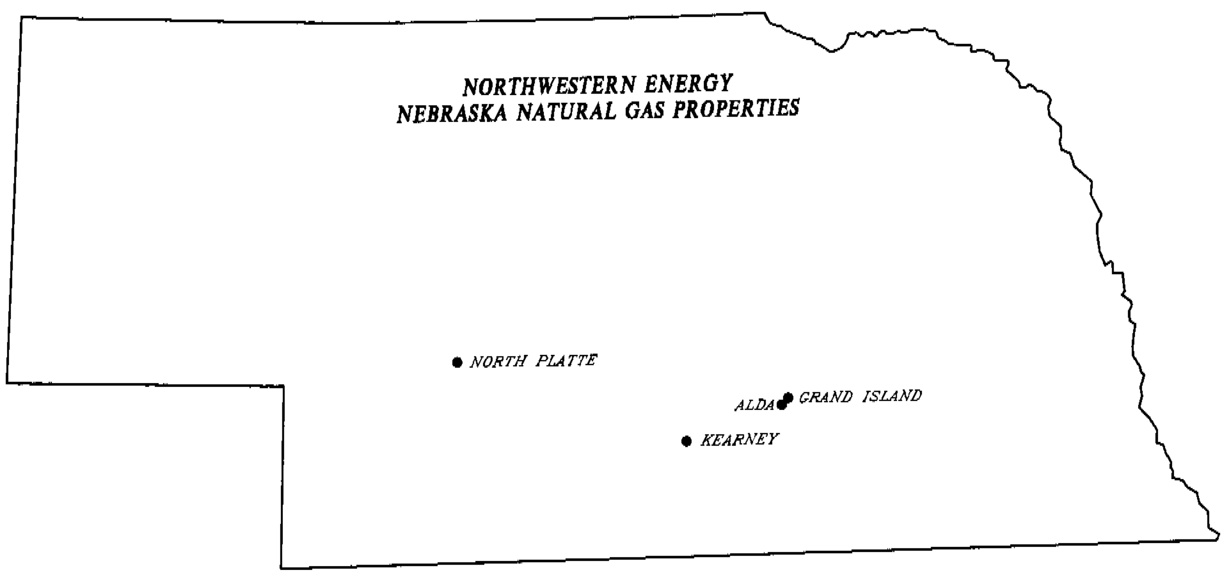
NorthWestern Energy

Tariffs - Final

NEBRASKA PUBLIC SERVICE COMMISSION
NATURAL GAS RATE SCHEDULE
for
NORTHWESTERN CORPORATION d/b/a NORTHWESTERN ENERGY

Section No. 2
Original Sheet No. 2
Canceling Sheet No.

NORTHWESTERN ENERGY
NEBRASKA RATE AREA



Date Filed: June 1, 2007 Effective Date: September 1, 2007

Issued By: Jeffrey Decker, Regulatory Department
Phone (605) 353-8315

NEBRASKA PUBLIC SERVICE COMMISSION
NATURAL GAS RATE SCHEDULE
for
NORTHWESTERN CORPORATION d/b/a NORTHWESTERN ENERGY

Section No. 3

1st Revised Sheet No. 1

Canceling Original Sheet No. 1

Rate No. 91

CLASS OF SERVICE: **Residential Gas Service**
RATE DESIGNATION: **Firm Sales**

1. Applicability

This rate is available to domestic customers whose maximum requirements for natural gas are not more than 200 therms per day. The nameplate input ratings of all gas burning equipment shall be used to determine a customer's maximum requirements, based on 10 hours use per day.

2. Territory

The area served with natural gas by the Company in Nebraska.

3. Rates

Monthly Charges:

Customer Charge per Meter:	$ 8.00
Non-Gas Commodity Charge:	
First 30 therms, per therm	$ 0.33737
Over 30 therms, per therm	$ 0.10513
Standby Capacity Charge - *December through March*:	$ 12.00
Minimum Monthly Bill:	$ 8.00

Adjustment Clauses:

a. Purchased Gas Cost Adjustment Clause shall apply. (Sheet Nos. 7, 7.1)

b. BTU Adjustment Clause shall apply. (Sheet Nos. 8, 8.1)

4. Other Provisions

The Standby Charge is applicable to customers using service pursuant to this schedule as a backup fuel source to an alternately fueled heating system. This charge is not applicable where natural gas service is the primary heating fuel source.

Service will be furnished under the Company's General Terms and Conditions.

Date Filed: June 1, 2007 **Effective Date: September 1, 2007**

Issued By: Jeffrey Decker, Regulatory Department
Phone (605) 353-8315

Rate No. 92

CLASS OF SERVICE: **General Gas Service**
RATE DESIGNATION: **Firm Sales**

1. **Applicability**
This rate is available to non-residential customers whose maximum requirements for natural gas are not more than 200 therms per day. If no historical peak day usage is available, the nameplate input ratings of all gas burning equipment shall be used to determine a customer's maximum requirements.

2. **Territory**
The area served with natural gas by the Company in Nebraska.

3. **Rates**

<u>Monthly Charges:</u>

Customer Charge per Meter:	$ 9.00
Non-Gas Commodity Charge:	
First 400 therms, per therm	$ 0.17150
Next 1,600 therms, per therm	$ 0.06343
Over 2,000 therms, per therm	$ 0.03743
***Standby Capacity Charge** - December through March*:	$ 37.00
<u>Minimum Monthly Bill:</u>	$ 9.00

<u>Adjustment Clauses:</u>
a. Purchased Gas Cost Adjustment Clause shall apply. (Sheet Nos. 7, 7.1)
b. BTU Adjustment Clause shall apply. (Sheet Nos. 8, 8.1)

4. **Other Provisions**
The Standby Charge is applicable to customers using service pursuant to this schedule as a backup fuel source to an alternately fueled heating system. This charge is not applicable where natural gas service is the primary heating fuel source.

Service will be furnished under the Company's General Terms and Conditions.

Issued By: Jeffrey Decker, Regulatory Department
Phone (605) 353-8315

CLASS OF SERVICE: **Commercial and Industrial**
RATE DESIGNATION: **Firm Sales**

Rate No. 94

1. **Applicability**
This rate is available for firm gas volumes, on a contract basis, to commercial and industrial customers who may also require volumes of interruptible gas in excess of firm demand volumes for which they have contracted.

2. **Territory**
The area served with natural gas by the Company in Nebraska.

3. **Rates**

Monthly Charges:

Customer Charge per Meter:	$ 80.00
Demand Charge – Standard Service:	
Per therm daily contract demand (never less than 50 therms)	$0.21910
Demand Charge – Extended Service:	
Per therm daily contract demand	
1st 500 therms/day (never less than 50 therms)	$0.24590
Over 500 therms/day	$0.00000
Non-Gas Commodity Charge:	
All use, per therm	$0.06331

Minimum Monthly Bill - Amount for therms of demand billed and the customer charge

Adjustment Clauses:

a. Purchased Gas Cost Adjustment Clause shall apply. (Sheet Nos. 7, 7.1)
b. BTU Adjustment Clause shall apply. (Sheet Nos. 8, 8.1)

4. **Penalty Provision**
If the customer takes unauthorized gas during the periods of curtailment, a penalty of $3.00 per therm shall be paid to the Company in addition to the commodity rate specified herein. In addition, the new daily use may then become the daily firm contract demand in place of the previous demand determined by the customer and cannot be reduced by the customer for a period of twelve months.

5. **Other Provisions**
Service will be furnished under the Company's General Terms and Conditions and the following provisions:
   1. Extended Service is Defined as Service contracted for a period of 5 years or more.
   2. A written contract shall be required for service hereunder.

Issued By: Jeffrey Decker, Regulatory Department
Phone (605) 353-8315

CLASS OF SERVICE: Commercial and Industrial – Interruptible

Rate Nos. 93 & 95
Irrigation Service - 93
Standard Service - 95

1. **Applicability**
Gas service under this rate schedule is available on an interruptible basis to any customer for commercial and industrial or irrigation purposes, provided that the customer's premises are adjacent to the Company's mains and that the capacity of the Company's system and the supply of gas available to it from its supplier is in excess of the requirements of its existing customers.

2. **Territory**
The area served with natural gas by the Company in Nebraska.

3. **Rates**
Monthly Charges:

Customer Charge per Meter:	
Irrigation Service – 93	$ 0.00
Standard Service – 95	$ 70.00
Non-Gas Commodity Charge all use, per therm:	
Irrigation Service – 93	$ 0.12975
Standard Service - 95	$ 0.06331
Minimum Monthly Bill:	
Irrigation Service – 93	$ 0.00
Standard Service – 95	$ 70.00

Adjustment Clauses:
a. Gas Cost Adjustment Clause shall apply. (Sheet Nos. 7, 7.1)
b. BTU Adjustment Clause shall apply. (Sheet Nos. 8, 8.1)

4. **Procedure For Curtailment Of Service**
Service rendered under this rate schedule shall be subject to curtailment by the Company in accordance with the priority guidelines as established by the Federal Regulatory Commission.

5. **Penalty Provision**
If Customer fails to comply with Company's request to curtail the use of gas, then all unauthorized gas so used shall be "Penalty Gas" and be paid for by the Customer at a rate based on the maximum penalty charges permitted to be made by the Company's supplier for takes of natural gas, in addition to the regular commodity charge for such gas.

(continued)

Issued By: Jeffrey Decker, Regulatory Department
Phone (605) 353-8315

CLASS OF SERVICE: Firm Transportation Service **RATE No. 96**

APPLICABILITY

This service is available to customers who have firm requirements less than 500 therms per day and who have made arrangements to have natural gas other than the Company's normal pipeline supply delivered to a Company town border station. Customers may transport volumes in excess of their firm contract on an interruptible basis.

TERRITORY

The area served with natural gas by the Company in Nebraska.

RATE

Customer Charge	$116.90
***Demand Charge – Standard Service*:**	
Per therm daily contract demand (never less than 50 therms)	$0.21910
***Demand Charge – Extended Service*:**	
Per therm daily contract demand	$0.24590
Transportation Service	
Negotiated Rate Not to Exceed the Non-Gas Transportation Rate (Rate 94)	$0.06331
Minimum Charge	Commitment Charge

Adjustment Clauses

a. Purchased Gas Cost Adjustment Clause shall apply (Sheet Nos. 7, 7.1).
a. BTU Adjustment Clause shall apply (Sheet Nos. 8, 8.1).

OTHER PROVISIONS

1. Extended Service is Defined as Service contracted for a period of 5 years or more
2. A written contract shall be required for service hereunder.
3. The customer shall sign a Transportation Service Agreement, which shall include the following:

(continued)

CLASS OF SERVICE: Interruptible Transportation Service **RATE No. 97**

APPLICABILITY

This schedule is available to interruptible customers who have requirements less than 500 therms per day and who have made arrangements to have natural gas other than the Company's normal pipeline supply delivered to a Company town border station.

TERRITORY

The area served with natural gas by the Company in Nebraska.

RATE

Customer charge per month	$116.90
Negotiated Rate Not to Exceed the Non-Gas Transportation Rate (Rate 94)	$0.06331
Minimum Charge	Customer Charge

Adjustment Clauses
a. BTU Adjustment Clause shall apply (Sheet Nos. 8, 8.1).

OTHER PROVISIONS

1. The customer shall sign a Transportation Service Agreement, which shall include the following:

   a. The customer shall, as directed, curtail or discontinue the use of natural gas upon two (2) hours notice by the Company;

   b. The customer shall provide and maintain suitable and adequate standby facilities and have, at all times, adequate standby fuel to maintain continuous plant operation during periods of curtailment in the delivery of natural gas hereunder;

(continued)

GENERAL TERMS AND CONDITIONS

APPLICABILITY

These General Terms and Conditions apply to all classes of Gas service unless otherwise indicated on the rate schedule.

POINT OF SERVICE ATTACHMENT

Point of service attachment is defined as that point where the facilities of the Company are physically connected to the facilities of the customer. In general, the point of service attachment is on the outlet side of the meter where the customer's fuel piping connects with the meter.

CUSTOMER'S INSTALLATION

The customer will furnish and own all fuel piping, equipment, appliances, fixtures and other devices necessary to distribute gas service from the point of service attachment. All such items furnished by the customer will be maintained by the customer at all times in conformity with the requirements of the constituted authorities and with the terms and conditions of the Company. The Company assumes no responsibility for the inspection and/or repair of defects in the Customer's piping, fixtures, or appliances.

CUSTOMER CONNECTION CHARGE

Customer Connection is defined as attaching a customer to receive utility service upon a request for service or reconnection of discontinued service. The Customer, Landlord or representative must be present during the Service turn-on. The connection charge will be billed to all customers applying for utility service. (Customer Connection does not include the reconnection of a customer whose utility services were discontinued due to nonpayment of utility bills. Reconnection charges for such customers are based on the Company's hourly rates for service work with a one-hour minimum.) The amount of the Customer Connection Charge will be $10.00 for all Customer Connections during normal business hours defined as 8:00 a.m. to 5:00 p.m., Monday through Friday, excluding legal holidays, and $125.00 for Customer Connections during other than regular business hours. The Company will attempt to reconnect a Customer on the same day as payment of all past due amounts is made, but the Company does not guaranty such reconnection will be completed during the same day. The Customer Connection Charge shall be paid by the Customer receiving utility service from the Company, and is due and payable upon presentation. If a bill is not paid, the Company shall have the right to refuse service.

Seasonal Use Customers (Grain Dryers, Asphalt Plants, Municipal Pools etc.) will be charged $80 for all Customer Connections during normal business hours defined as 8:00 a.m. to 5:00 p.m., Monday through Friday, excluding legal holidays, and $125.00 for Customer Connections during other than regular business hours. The Customer Connection Charge shall be paid by the Customer receiving utility service from the Company, and is due and payable upon presentation. If a bill is not paid, the Company shall have the right to refuse service.

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OWNER'S CONSENT TO OCCUPY

In case the Customer is not the owner of the premises or of the intervening property between the premises and the Company's lines, the Customer will obtain from the property owner(s) the necessary consent to install and maintain in said premises all such gas equipment as is necessary or convenient for supplying gas to the Customer.

ACCESS TO PREMISES

The Company has the right to access to the Customer's premises at all reasonable times for the purpose of installing, reading, inspecting, or repairing any meters, devices and other equipment used in connection or disconnection of any or all service equipment, for the purpose of removing its property, and for all other proper purposes.

Access to the meter is required for the Company to read the meter. If access is not provided, the Company may estimate the billing for up to three consecutive months. The Company will notify the Customer upon each unsuccessful attempt to access the meter. If access has not been provided at the end of the three consecutive month period, the Company may charge a $20 Special Access Fee, in order to secure an actual read of the meter.

PROTECTION OF COMPANY'S PROPERTY

The Customer will properly protect the Company's property on the Customer's premises from loss or damage and will permit no one who is not an agent of the Company to remove or tamper with the Company's property.

METERING

The service used will be measured by a meter or meters to be furnished and installed by the Company at its own expense and upon the registration of said meters all bills will be calculated. If more than one meter is installed on different classes of service (each class being charged for at different rates) each meter will be considered by itself in calculating the amount of any bill, except as otherwise provided on a specific rate schedule. Meters include all measuring instruments.

BYPASSING OR TAMPERING WITH METERING FACILITIES

Customers shall not interfere in any way with the metering facilities after they have been set in place. In cases where the meter seal is broken or the working parts of the meter have been tampered with or the meter damaged or there is evidence that a bypass has been used, the Utility may render a bill for the current billing period based upon the estimated use, considering past experience under similar conditions and may, in addition thereto, charge for the actual cost of repairing or replacing said meter and connections. Service may be discontinued or refused at the premises where such bypassing or tampering has occurred until all such charges are paid. Legal action may also be pursued in the instance of meter tampering.

(continued)

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SUBMETERING

Submetering will not be permitted unless it is at the same premises and either the Customer or the Company have compelling reasons for not combining the existing services into one service and one meter. Under no circumstances shall a Customer's fuel piping cross a public street or alley.

MASTER METERING

All buildings, mobile home parks, and trailer courts for which construction was begun after June 13, 1980, shall be metered separately for each residential or commercial unit, with the exception of hospitals, nursing homes, transient hotels and motels, dormitories, campgrounds, other residential facilities of a purely transient nature, central heating or cooling systems, central ventilating systems, central hot water systems, residential multiple occupancy buildings constructed, owned or operated with funds appropriated through the Department of Housing and Urban Development or any other federal or state government agency. Any existing multiple occupancy building receiving master metered service which is substantially remodeled or renovated for continued use as a multiple occupancy building shall be individually metered unless the owner of such building demonstrates that conversion from master metering to individual metering would be impractical, uneconomical, or unfeasible.

MONTHLY BILLS

(a) Bills for service will be rendered monthly unless otherwise applied.
(b) Failure to receive a bill in no way exempts Customers from the provisions of these Terms and Conditions.
(c) The Company will attempt to read a meter at least bi-monthly, and any billings between actual readings or when the Company is unable to read a meter after a reasonable effort has been made will be based upon prior usage, adjusted for weather conditions.
(d) To the rates herein set forth, the Company may add all or any part of any special charge or special tax now imposed upon the Company by any governmental authority, or any new, special, or additional charge or tax which might be imposed as a result of laws, rules, regulations, or ordinances which may be amended, changed, adopted, or enacted by any governmental authority subsequent to the effective date hereof.

TERMS OF PAYMENT

Bills will be due upon receipt; timely payment may be made up until the 20th day. On the 20th day after billing, an account with an unpaid balance of $5.00 or more will be considered late and a late payment charge will apply. The late payment charge shall be 1% of the unpaid balance plus a collection charge of $2.00. Where a Customer is disconnected for nonpayment of a bill, a reconnection charge will be made in accordance with currently effective Company Re-Connection Policy.

(continued)

(continued)

CUSTOMER DEPOSITS

The Company may request that a Customer, when applying for service, provide credit information and may request a security deposit if the Customer has an unsatisfactory credit history, has established an unsatisfactory payment record with the Company, or has an outstanding undisputed and unpaid service amount owed the Company. The Company may also request a security deposit from an existing Customer who has had three or more disconnection notices in the past twelve months. The amount of a security deposit shall be not more than one-sixth of the estimated annual bill, and the Company may accept a letter of credit or guarantor in lieu of the security deposit. If a customer is unable to pay the full amount of a deposit, the Company will accept payment of the deposit in installments over a period of not more than four (4) months. Upon disconnection of service and receipt of the final payment from the Customer, the Company shall refund the Customer's deposit plus accrued interest, or the balance, if any, in excess of the unpaid bills for service furnished by the Company. Interest on a Customer's deposit shall earn simple interest of three percent (3%) per annum. If a Customer has paid his bills for service for twelve (12) consecutive months by the due date for such bills, the Company will automatically refund the deposit plus accrued interest to the Customer.

CONDITIONS FOR REFUSAL OR DISCONNECTION OF SERVICE

The Company may refuse or disconnect service for any of the following reasons:

(a) Customer has requested disconnection (the Company may require up to forty-eight hours' written notice).
(b) An unsafe service condition exists on the Customer's premises, which is likely to cause injury to person or property.
(c) An other condition of the Customer's premises makes it unsafe for the Company to perform work on such premises.
(d) Customer has a delinquent service bill, and the Company has provided proper notice.
(e) Customer has failed to provide credit information, pay a security deposit, pay an additional deposit, or provide a guarantee.
(f) Customer has failed to comply with any of the provisions of the applicable Company tariff.
(g) Customer has failed to comply with interruption or curtailment orders issued by the Company.
(h) Customer is indebted to the Company for past bills incurred and refuses to liquidate the debt.
(i) Customer, although not personally liable to the Company, is attempting to return service to an indebted household and no attempts are forthcoming to liquidate the debt of that household. An indebted household exists when the person applying for service (1) was a member of the household when the prior debt was incurred by someone else living in that household, whether at the same address or at a new one, or (2) has moved into the same apartment or building in which the prior bill was incurred, and the person who owes the debt is still living there.
(j) A connection, device, or bypass is found on the meter, regulating equipment, or piping of the Customer which prevents the meter from properly registering consumption, or a meter is found with broken seals or otherwise shows evidence of tampering.

(continued)

(k) Customer has otherwise received the benefit of service with respect to the account or has been guilty of fraud or misrepresentation with regard to service.

(l) Customer refuses to allow authorized Company personnel onto the Customer's premises for purposes of examining the piping, appliances, and other equipment relating to the Company's service; reading the meter, ascertaining connected loads to turn on service, obtain an actual meter reading, to inspect a suspected safety problem, or to perform maintenance work.

(m) Any other reason where authority is specifically granted by Nebraska statute or applicable administrative rule.

DISPUTE RESOLUTION

Pursuant to the provisions of Revised Statutes of Nebraska, 1996 Reissue, Sections 70-1608 through 70-1614, a Customer may request a conference in regard to any dispute over a proposed disconnection of service with the Company. A designated employee of the Company will hear and decide all matters related to the dispute. If a residential Customer disputes the proposed disconnection of service and provides a written statement to the Company setting forth the reasons for the dispute and the relief requested, a conference shall be held between the Company and the Customer before service will be disconnected. Upon receipt of such a written statement, the Company will notify the Customer, in writing, of the time, place, and date scheduled for the conference, which shall be within fourteen (14) days of the Customer's request. At such conference, the employee designated by the Company to hear such dispute, shall, based solely upon the evidence presented, affirm, reverse, or modify any Company decision involving the disputed bill. The employee shall allow termination of utility service only as a measure of last resort after he has exhausted all other remedies less drastic than termination. The Customer may appeal an adverse decision of the Company employee to a management office of the Company, and a hearing will be held to resolve the dispute. At such hearing, the Customer may be represented by legal counsel or other representative or spokesperson, examine the Company's files and records pertaining to all matters directly relevant to the dispute or utilized by the Company in reaching the decision to propose termination, present witnesses and offer evidence, confront and cross-examine witnesses, and make or have made a record of the proceedings at his own expense.

Budget Payment Plan

The Company's Budget Bill Plan (BBP) is available to residential and commercial customers. It may be initiated for a customer at any time during the year, provided that the customer has paid all outstanding utility charges due the Company.

The company will have a billing practice under which a Customer may be billed monthly for a percentage or portion of the Customer's total annual consumption as estimated by the Utility. The

(continued)

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purpose of such budget billing is to provide, insofar as it is practicable to do so, a uniform monthly bill.

Each BBP account will be reviewed by the Company at least semi-annually, based on their Budget Billing start date, to determine if an adjustment to the budget amount is necessary, to minimize annual over/under collection balances. The new BPP will be determined by adding the customers actual debit or credit balance, at the time of review, to the customer's prior 12 months billings under current tariff rates, adjusted for normal weather, known changes in consumption, and projected Adjustment Clause price increases or decreases, the sum of which is divided by twelve. Where prior billings are not available, the Company will estimate billings using the best available information of customer's consumption.

Should a customer request that the Company not take the actual debit or credit balance into consideration when calculating a revised budget amount, the Company will issue a check to a customer with a credit balance or bill the customer for any debit balance.

Service to customers participating in the BPP shall be pursuant to the General Terms and Conditions of service including the Terms of Payment provisions contained therein, provided, however, that service to a BBP customer will not be disconnected for non-payment if the customer has a credit balance in his account. A customer may discontinue participation in the BBP at any time.

PEAK SHAVING GAS SUPPLIES

The Company may supply gas from any stand-by equipment provided that the gas so supplied shall be reasonably equivalent to the natural gas normally supplied hereunder.

RESALE PROHIBITED

All gas purchased under any rate schedule shall not be resold by the purchaser thereof in any manner.

SERVICE LINE INSTALLATION

For services, except mobile homes in mobile home parks, the Company will install a service along the shortest feasible route from the gas main to the customer's building upon the customer making a non-refundable contribution based upon the distance from the customer's property line to the point of service attachment as follows:

For residential customers using natural gas as their primary heating source and for water heating: the customer will be charged a $90.00 connection fee for the first 150 feet of service pipe. Any distance beyond 150 feet may result in the company requiring

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an Advance for Construction or a Contribution in Aid of Construction based on the consideration of revenues from the project and the cost of the construction.

For residential customers using natural gas for space heating only, fireplace only, water heating only, natural gas grill only, or any combination other than primary space heating and water heating as described above: the Company will consider the total cost of serving the Customer and the expected revenue from the Customer. In this determination, if the project is not economically feasible, the Company may require an Advance for Construction or a Contribution in Aid of Construction from the customer to aid in the construction expense to serve the Customer.

For services to mobile homes in mobile home parks, a non-refundable contribution of $75.00 will be made by the customer for services up to 50 feet of horizontal piping in the mobile home lot. For service over 50 feet, or where the load does not consist of a natural gas furnace and a natural gas water heater, an additional non-refundable contribution may be required as described in the preceding paragraph.

Commercial and Industrial Customers: The Company may install natural gas service or main without charge where the Company deems the anticipated revenue from the customer is sufficient to justify the service or main extension. The Company will apply the general principle that the rendering of natural gas service to the applicant shall be economically feasible so that the cost of extending such service will not have an undue burden on other customers. In determining whether the expenditure of natural gas service or main is economically feasible, the Company shall take into consideration the total cost of serving the Customer and the expected revenue from the Customer. If the Company determines that the extension of service or main to the Customer is not economically feasible, the Company may require an Advance for Construction or a Contribution in Aid of Construction from the customer or customers to aid expansion. In instances where the project is not paid in advance, the Company may require a Letter of Credit or other Guarantee to secure the cost of the project. Projects that term longer than one year will carry interest at the rate of the allowed rate of return in the Company' most recent gas cost of service determination.

In instances where a Contribution in Aid of Construction is required, three years after the project has been completed, the Company will have the option to review the three-year average use. If the actual volumes vary from projected volumes by 20% or more, the Company has the option to charge or credit the customer for the variance, without interest, in projected Contribution in Aid of Construction.

(continued)

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(continued)

Installation of gas service lines are scheduled by the Company for completion during the regular construction season. The Company may make a charge for added cost of the construction of a gas service line if the installation is required other than during the regular construction season.

The Company will not install Gas Services and Mains until the surface has been graded to within six inches of a permanent established elevation.

BILLING DAY AND CURTAILMENT OF GAS

The billing day for the purpose of determining the amount of gas used will be from 9:00 a.m. CCT (Central Clock Time) one day until 9:00 a.m. CCT the next day. The Company shall have the right to curtail or limit the Customer's use of gas during any billing day to the Contract Demand then in effect when demand by firm and higher priority interruptible natural gas purchasers exceeds available pipeline supply. Curtailment of interruptible gas will commence at 9:00 a.m. CCT at the start of a new billing day. Under normal circumstances, notice of curtailment of interruptible gas will be given to Customer by 3:00 p.m. CCT, prior to the beginning of the gas day in which curtailment is to begin. However, in cases of emergency (to be determined solely by the Company) any notice prior to 9:00 a.m. CCT is deemed to place the curtailment in effect at 9:00 a.m. CCT, and such curtailment shall continue in effect until the Company notifies Customer that the curtailment is released. In cases of emergency when notice of curtailment cannot reasonably be given immediately prior to a new billing day, Customer will cooperate with the Company by curtailing its use of interruptible gas as soon as possible after notice of curtailment by Company. Proper notice of curtailment will be deemed to have been given when any person or persons authorized to receive curtailment orders on behalf of Customer has been notified by telephone or in person by a representative of Company.

The Company will endeavor to give the Customer as much notice as possible with respect to curtailment of service. Customer agrees to provide and maintain complete standby facilities and have available at all times sufficient standby fuel to maintain continuous plant operations during complete curtailment in the delivery of natural gas.

CONTINUITY OF SERVICE, INTERRUPTIONS, AND LIABILITY

The Company will endeavor to provide continuous service but does not guarantee an uninterrupted or undisturbed supply of gas service. The Company will not be responsible for any loss or damage resulting from the interruption or disturbance of service for any cause other than negligence of the Company. The Company will not be liable for any loss of profits or other consequential damages resulting from the use of service or any interruption or disturbance of service.

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The Company shall use due care and diligence to furnish gas service near the normal pressure levels and in accordance with the acceptable levels of delivery pressure as may exist under operating conditions in the pipeline and distribution system. Because delivery pressure may vary, the customer shall install, operate, and maintain, at his own expense such pressure regulating devices as may be necessary to regulate the pressure of gas after its delivery to the customer. The Company shall not be liable for the control of gas pressure or gas after delivery of gas to the consumer.

Neither Customer nor the Company shall have any claim against the other for damages sustained as a result of interruptions of gas deliveries caused by Acts of God, weather conditions, labor disturbances, fires, accidents, breakage or repair of pipeline, mechanical failure of any machinery, equipment or other mechanical devices, shortage of gas supply, or other causes or contingencies beyond the reasonable control of and occurring without negligence on the part of such other party. When such causes or contingencies cease to be operative, delivery and receipt of gas shall resume as soon as practicable. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the party affected. Any such cause or contingency, however, exempting customers from liability for non-performance (except where prevented by valid orders or requirements of Federal, State, or other governmental regulatory bodies having jurisdiction in the premises) shall not relieve customer of its obligation to pay minimum charges in accordance with the applicable rate schedule.

The Customer agrees to save, indemnify and hold the Company harmless from any and all claims, damage, or injury to persons or property arising from any cause whatsoever after the delivery of gas by the Company to the point of service attachment, except where such injury or damage is shown to have been caused solely by the negligence of the Company. The Customer shall not be liable for any loss, damage, or injury to persons or property arising from any cause whatsoever before the actual delivery of gas to the point of service attachment, except where such injury or damage is shown to have arisen solely from the negligence of the Customer. The Customer assumes all responsibility for all service and equipment at and from the Customer's point of service attachment of such service, and will protect and save the Company harmless from all claims for injury or damage to persons or property occurring by such services and equipment, except where said injury or damage is shown to have been occasioned solely by the negligence of the Company.

<u>DELIVERY PRESSURE</u>

The volume of gas measured, where delivered at other than 0.25 p.s.i.g. at the customer's meter, shall be adjusted to a base pressure equal to 14.73 p.s.i.a. in accordance with accepted standards for measurement of gas at varying pressures.

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METER ACCURACY AND TESTING OF METERS

A Customer may request the Company to test his meter, and the Company will make the test as soon as practical after the request. If a request is made within one year after a previous request, the Company may require a Customer to pay a reasonable deposit for the test. The deposit will be refunded if the meter is found to have an error of more than two percent (2%) fast, and the Company will refund to the Customer the percentage of the inaccuracy of the billed amount for the period equal to one-half the time elapsed since the most recent test, but not to exceed six (6) months. If the meter is found to have an error of more than two percent (2%) slow, the Company may bill the Customer for the percentage of the inaccuracy of the billed amount for the period equal to one-half the time elapsed since the most recent test, but not to exceed six (6) months.

PRIORITY OF SERVICE

All Customers will be classified according to priorities. The Company may require curtailments of natural gas at any time in order to protect deliveries of natural gas having a higher priority. The Company shall have the right to curtail use of natural gas in any community due to capacity limitations of facilities of either the pipeline supplier or the Company, even though service is continued for lower priority customers in another community. When the Company is unable to supply the full natural gas requirements of all its customers, curtailment of natural gas service will progress in the following sequence: Priorities 4, 3, 2 and 1. The Company, at its discretion, shall have the right to curtail / interrupt based on other operational factors.

Priority 1: Firm residential and small commercial requirements less than 500 therms on a peak day. Curtailment within this priority will, where operationally possible, be on a pro rata basis.

Priority 2: Firm commercial requirements from 500 through 1,999 therms on a peak day, and industrial requirements from 0 through 1,999 therms on a peak day. Curtailment within this priority will, where operationally possible, be on a pro rata basis.

Priority 3: Firm commercial and industrial requirements greater than 2,000 therms on a peak day. Curtailment within this priority will, where operationally possible, be on a pro rata basis.

Priority 4: Interruptible commercial and industrial requirements. The Company may curtail a customer's usage regardless of priority if the customer elects to take interruptible service. Curtailment, where possible, will be ordered on the basis of lowest to highest non-gas margin regardless of jurisdiction or end-use.

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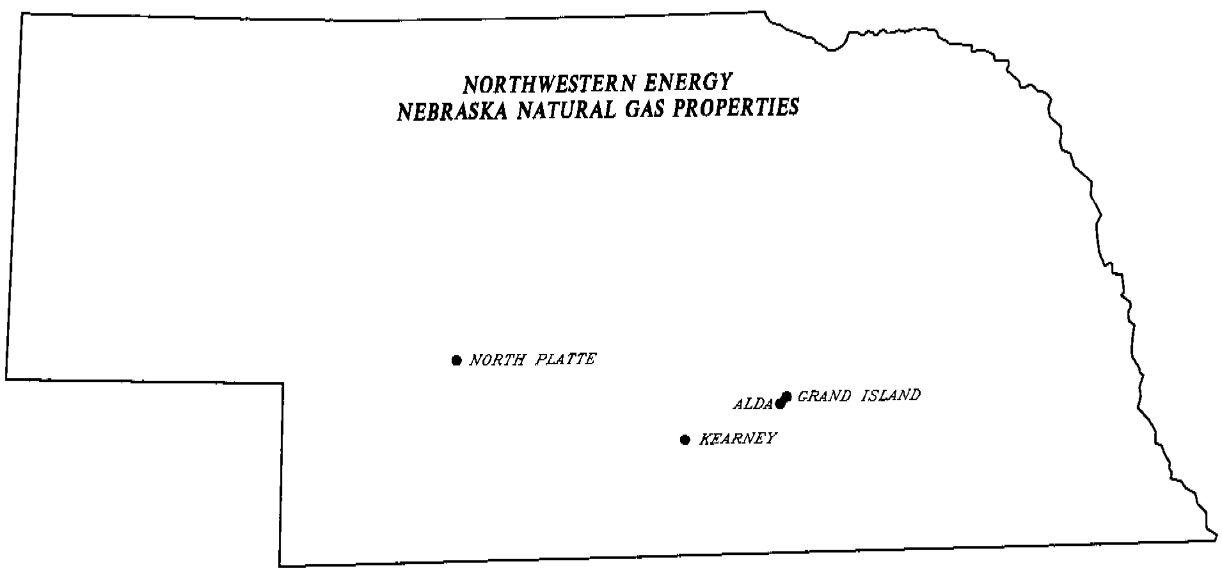
Tariffs – Red Line Version

NORTHWESTERN ENERGY
NEBRASKA RATE AREA



Section No. 3
~~Original~~ 1st Revised— Sheet No. 1
Canceling Original— Sheet No.

CLASS OF SERVICE:	**Residential Gas Service**	**Rate No. 91**
RATE DESIGNATION:	**Firm Sales**	

1. **Applicability**
This rate is available to domestic customers whose maximum requirements for natural gas are not more than 200 therms per day. The nameplate input ratings of all gas burning equipment shall be used to determine a customer's maximum requirements, based on 10 hours use per day.

2. **Territory**
The area served with natural gas by the Company in Nebraska.

3. **Rates**
Monthly Charges:

Customer Charge per Meter:	$ ~~5.00~~8.00
Non-Gas Commodity Charge:	
First 30 therms, per therm	$ 0.~~26356~~ .33737
Over 30 therms, per therm	$ 0.~~09513~~ .10513
***Standby Capacity Charge** - December through March*:	$ 12.00
Minimum Monthly Bill:	$ ~~5.00~~ 8.00

Adjustment Clauses:
a. Purchased Gas Cost Adjustment Clause shall apply. (Sheet Nos. 7, 7.1)
b. BTU Adjustment Clause shall apply. (Sheet Nos. 8, 8.1)

4. **Other Provisions**
The Standby Charge is applicable to customers using service pursuant to this schedule as a backup fuel source to an alternately fueled heating system. This charge is not applicable where natural gas service is the primary heating fuel source.

Service will be furnished under the Company's General Terms and Conditions.

CLASS OF SERVICE: **General Gas Service**
RATE DESIGNATION: **Firm Sales**

Rate No. 92

1. **Applicability**
This rate is available to non-residential customers whose maximum requirements for natural gas are not more than 200 therms per day. If no historical peak day usage is available, the nameplate input ratings of all gas burning equipment shall be used to determine a customer's maximum requirements.

2. **Territory**
The area served with natural gas by the Company in Nebraska.

3. **Rates**
Monthly Charges:

Customer Charge per Meter:	$ ~~6.00~~ 9.00
Non-Gas Commodity Charge:	
First 400 therms, per therm	$ 0.~~12101~~ .17150
Next 1,600 therms, per therm	$ 0.~~05343~~ .06343
Over 2,000 therms, per therm	$ 0.~~03243~~ .03743
***Standby Capacity Charge** - December through March*:	$ 37.00
Minimum Monthly Bill:	$ ~~6.00~~ 9.00

Adjustment Clauses:
a. Purchased Gas Cost Adjustment Clause shall apply. (Sheet Nos. 7, 7.1)
b. BTU Adjustment Clause shall apply. (Sheet Nos. 8, 8.1)

4. **Other Provisions**
The Standby Charge is applicable to customers using service pursuant to this schedule as a backup fuel source to an alternately fueled heating system. This charge is not applicable where natural gas service is the primary heating fuel source.

Service will be furnished under the Company's General Terms and Conditions.

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NEBRASKA PUBLIC SERVICE COMMISSION
NATURAL GAS RATE SCHEDULE
for
NORTHWESTERN CORPORATION, d/b/a NORTHWESTERN ENERGY

Section No. 3

~~Original~~ 1st Revised Sheet No. 3

Canceling Original Sheet No.

CLASS OF SERVICE: **Commercial and Industrial** **Rate No. 94**
RATE DESIGNATION: **Firm Sales**

1. **Applicability**
This rate is available for firm gas volumes, on a contract basis, to commercial and industrial customers who may also require volumes of interruptible gas in excess of firm demand volumes for which they have contracted.

2. **Territory**
The area served with natural gas by the Company in Nebraska.

3. **Rates**

Monthly Charges:

Customer Charge per Meter:	$ 80.00
Demand Charge – Standard Service:	
Per therm daily contract demand (never less than 50 therms)	$0.21910
Demand Charge – Extended Service:	
Per therm daily contract demand	
1st 500 therms/day (never less than 50 therms)	$0.24590
Over 500 therms/day	$0.00000
Non-Gas Commodity Charge:	
All use, per therm	$0.~~04530~~ .06331

Minimum Monthly Bill - Amount for therms of demand billed and the customer charge

Adjustment Clauses:

a. Purchased Gas Cost Adjustment Clause shall apply. (Sheet Nos. 7, 7.1)
b. BTU Adjustment Clause shall apply. (Sheet Nos. 8, 8.1)

4. **Penalty Provision**
If the customer takes unauthorized gas during the periods of curtailment, a penalty of $3.00 per therm shall be paid to the Company in addition to the commodity rate specified herein. In addition, the new daily use may then become the daily firm contract demand in place of the previous demand determined by the customer and cannot be reduced by the customer for a period of twelve months.

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5. **Other Provisions**
Service will be furnished under the Company's General Terms and Conditions and the following provisions:
1. Extended Service is Defined as Service contracted for a period of 5 years or more.
2. A written contract shall be required for service hereunder.

CLASS OF SERVICE: Commercial and Industrial – Interruptible

Rate Nos. 93 & 95
Irrigation Service - 93
Standard Service - 95

1. **Applicability**
Gas service under this rate schedule is available on an interruptible basis to any customer for commercial and industrial or irrigation purposes, provided that the customer's premises are adjacent to the Company's mains and that the capacity of the Company's system and the supply of gas available to it from its supplier is in excess of the requirements of its existing customers.

2. **Territory**
The area served with natural gas by the Company in Nebraska.

3. **Rates**

Monthly Charges:

Customer Charge per Meter:	
Irrigation Service – 93	$ 0.00
Standard Service – 95	$ 70.00
Non-Gas Commodity Charge all use, per therm:	
Irrigation Service – 93	$ 0.~~09026~~ .12975
Standard Service - 95	$ 0.~~04530~~ .06331
Minimum Monthly Bill:	
Irrigation Service – 93	$ 0.00
Standard Service – 95	$ 70.00

Adjustment Clauses:
a. Gas Cost Adjustment Clause shall apply. (Sheet Nos. 7, 7.1)
b. BTU Adjustment Clause shall apply. (Sheet Nos. 8, 8.1)

4. **Procedure For Curtailment Of Service**

Service rendered under this rate schedule shall be subject to curtailment by the Company in accordance with the priority guidelines as established by the Federal Regulatory Commission.

5. Penalty Provision
If Customer fails to comply with Company's request to curtail the use of gas, then all unauthorized gas so used shall be "Penalty Gas" and be paid for by the Customer at a rate based on the maximum penalty charges permitted to be made by the Company's supplier for takes of natural gas, in addition to the regular commodity charge for such gas.

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6. Other Provisions
Service will be furnished under the Company's General Terms and Conditions and the following provision:

1. A written agreement shall be required for service hereunder.

NEBRASKA PUBLIC SERVICE COMMISSION
NATURAL GAS RATE SCHEDULE
for
NORTHWESTERN CORPORATION, d/b/a NORTHWESTERN ENERGY

Section No. 3
Original Sheet No. 5
Canceling Sheet No.

CLASS OF SERVICE: Firm Transportation Service **RATE No. 96**

APPLICABILITY

This service is available to customers who have firm requirements less than 500 therms per day and who have made arrangements to have natural gas other than the Company's normal pipeline supply delivered to a Company town border station. Customers may transport volumes in excess of their firm contract on an interruptible basis.

TERRITORY

The area served with natural gas by the Company in Nebraska.

RATE

Customer Charge	$116.90
~~Commitment charge per month per therm contracted~~	~~$1.20447~~
Demand Charge – Standard Service:	
Per therm daily contract demand (never less than 50 therms)	$0.21910
Demand Charge – Extended Service:	
Per therm daily contract demand	$0.24590

Transportation Service

Negotiated Rate Not to Exceed the Non-Gas Transportation Rate (Rate 94) ~~$0.0453~~ .06331

Minimum Charge — Commitment Charge

Adjustment Clauses

a. Purchased Gas Cost Adjustment Clause shall apply (Sheet Nos. 7, 7.1).
a. BTU Adjustment Clause shall apply (Sheet Nos. 8, 8.1).

OTHER PROVISIONS

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1. Extended Service is Defined as Service contracted for a period of 5 years or more

2. A written contract shall be required for service hereunder.

3. The customer shall sign a Transportation Service Agreement, which shall include the following:

(continued)

CLASS OF SERVICE: Interruptible Transportation Service **RATE No. 97**

APPLICABILITY

This schedule is available to interruptible customers who have requirements less than 500 therms per day and who have made arrangements to have natural gas other than the Company's normal pipeline supply delivered to a Company town border station.

TERRITORY

The area served with natural gas by the Company in Nebraska.

RATE

Customer charge per month	$116.90
Negotiated Rate Not to Exceed the Non-Gas Transportation Rate (Rate 94)	~~$0.04530~~ .06331
Minimum Charge	Customer Charge

Adjustment Clauses
a. BTU Adjustment Clause shall apply (Sheet Nos. 8, 8.1).

OTHER PROVISIONS
1. The customer shall sign a Transportation Service Agreement, which shall include the following:

   a. The customer shall, as directed, curtail or discontinue the use of natural gas upon two (2) hours notice by the Company;

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b. The customer shall provide and maintain suitable and adequate standby facilities and have, at all times, adequate standby fuel to maintain continuous plant operation during periods of curtailment in the delivery of natural gas hereunder;

(continued)

GENERAL TERMS AND CONDITIONS

APPLICABILITY

These General Terms and Conditions apply to all classes of Gas service unless otherwise indicated on the rate schedule.

POINT OF SERVICE ATTACHMENT

Point of service attachment is defined as that point where the facilities of the Company are physically connected to the facilities of the customer. In general, the point of service attachment is on the outlet side of the meter where the customer's fuel piping connects with the meter.

CUSTOMER'S INSTALLATION

The customer will furnish and own all fuel piping, equipment, appliances, fixtures and other devices necessary to distribute gas service from the point of service attachment. All such items furnished by the customer will be maintained by the customer at all times in conformity with the requirements of the constituted authorities and with the terms and conditions of the Company. The Company assumes no responsibility for the inspection and/or repair of defects in the Customer's piping, fixtures, or appliances.

CUSTOMER CONNECTION CHARGE

Customer Connection is defined as attaching a customer to receive utility service upon a request for service or reconnection of discontinued service. The Customer, Landlord or representative must be present during the Service turn-on. The connection charge will be billed to all customers applying for utility service. (Customer Connection does not include the reconnection of a customer whose utility services were discontinued due to nonpayment of utility bills. Reconnection charges for such customers are based on the Company's hourly rates for service work with a one-hour minimum.) The amount of the Customer Connection Charge will be $10.00 for all Customer Connections during normal business hours defined as 8:00 a.m. to 5:00 p.m., Monday through Friday, excluding legal holidays, and $~~15.00~~125.00 for Customer Connections during other than regular business hours. The Company will attempt to reconnect a Customer on the same day as payment of all past due amounts is made, but the Company does not guaranty such reconnection will be completed during the same day. The Customer Connection Charge shall be paid by the Customer receiving utility service from the Company, and is due and payable upon presentation. If a bill is not paid, the Company shall have the right to refuse service.

Seasonal Use Customers (Grain Dryers, Asphalt Plants, Municipal Pools etc.) will be charged $80 for all Customer Connections during normal business hours defined as 8:00 a.m. to 5:00 p.m., Monday through Friday, excluding legal holidays, and $125.00 for Customer Connections during other than regular business hours. The Customer Connection Charge shall be paid by the

Customer receiving utility service from the Company, and is due and payable upon presentation. If a bill is not paid, the Company shall have the right to refuse service.

OWNER'S CONSENT TO OCCUPY

In case the Customer is not the owner of the premises or of the intervening property between the premises and the Company's lines, the Customer will obtain from the property owner(s) the necessary consent to install and maintain in said premises all such gas equipment as is necessary or convenient for supplying gas to the Customer.

(continued)

GENERAL TERMS AND CONDITIONS
(continued)

ACCESS TO PREMISES

The Company has the right to access to the Customer's premises at all reasonable times for the purpose of installing, reading, inspecting, or repairing any meters, devices and other equipment used in connection or disconnection of any or all service equipment, for the purpose of removing its property, and for all other proper purposes.

Access to the meter is required for the Company to read the meter. If access is not provided, the Company may estimate the billing for up to three consecutive months. The Company will notify the Customer upon each unsuccessful attempt to access the meter. If access has not been provided at the end of the three consecutive month period, the Company may charge a $20 Special Access Fee, in order to secure an actual read of the meter.

PROTECTION OF COMPANY'S PROPERTY

The Customer will properly protect the Company's property on the Customer's premises from loss or damage and will permit no one who is not an agent of the Company to remove or tamper with the Company's property.

METERING

The service used will be measured by a meter or meters to be furnished and installed by the Company at its own expense and upon the registration of said meters all bills will be calculated. If more than one meter is installed on different classes of service (each class being charged for at different rates) each meter will be considered by itself in calculating the amount of any bill, except as otherwise provided on a specific rate schedule. Meters include all measuring instruments.

BYPASSING OR TAMPERING WITH METERING FACILITIES

Customers shall not interfere in any way with the metering facilities after they have been set in place. In cases where the meter seal is broken or the working parts of the meter have been tampered with or the meter damaged or there is evidence that a bypass has been used, the Utility may render a bill for the current billing period based upon the estimated use, considering past experience under similar conditions and may, in addition thereto, charge for the actual cost of repairing or replacing said meter and connections. Service may be discontinued or refused at the premises where such bypassing or tampering has occurred until all such charges are paid. Legal action may also be pursued in the instance of meter tampering.

SUBMETERING

Submetering will not be permitted unless it is at the same premises and either the Customer or the Company have compelling reasons for not combining the existing services into one service and one meter. Under no circumstances shall a Customer's fuel piping cross a public street or alley.

MASTER METERING

All buildings, mobile home parks, and trailer courts for which construction was begun after June 13, 1980, shall be metered separately for each residential or commercial unit, with the exception of hospitals, nursing homes, transient hotels and motels, dormitories, campgrounds, other residential facilities of a purely transient nature, central heating or cooling systems, central ventilating systems, central hot water systems, residential multiple occupancy buildings constructed, owned or operated with funds appropriated through the Department of Housing and Urban Development or any other federal or state government agency. Any existing multiple occupancy building receiving master metered service which is substantially remodeled or renovated for continued use as a multiple occupancy building shall be individually metered unless the owner of such building demonstrates that conversion from master metering to individual metering would be impractical, uneconomical, or unfeasible.

(continued)

GENERAL TERMS AND CONDITIONS
(continued)

MONTHLY BILLS

(a) Bills for service will be rendered monthly unless otherwise applied.
(b) Failure to receive a bill in no way exempts Customers from the provisions of these Terms and Conditions.

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(c) The Company will attempt to read a meter at least bi-monthly, and any billings between actual readings or when the Company is unable to read a meter after a reasonable effort has been made will be based upon prior usage, adjusted for weather conditions.

(d) To the rates herein set forth, the Company may add all or any part of any special charge or special tax now imposed upon the Company by any governmental authority, or any new, special, or additional charge or tax which might be imposed as a result of laws, rules, regulations, or ordinances which may be amended, changed, adopted, or enacted by any governmental authority subsequent to the effective date hereof.

TERMS OF PAYMENT

Bills will be due upon receipt; timely payment may be made up until the 20th day. On the 20th day after billing, an account with an unpaid balance of $5.00 or more will be considered late and a late payment charge will apply. The late payment charge shall be 1% of the unpaid balance plus a collection charge of $2.00. Where a Customer is disconnected for nonpayment of a bill, a reconnection charge will be made in accordance with currently effective Company Re-Connection Policy.

CUSTOMER DEPOSITS

The Company may request that a Customer, when applying for service, provide credit information and may request a security deposit if the Customer has an unsatisfactory credit history, has established an unsatisfactory payment record with the Company, or has an outstanding undisputed and unpaid service amount owed the Company. The Company may also request a security deposit from an existing Customer who has had three or more disconnection notices in the past twelve months. The amount of a security deposit shall be not more than one-sixth of the estimated annual bill, and the Company may accept a letter of credit or guarantor in lieu of the security deposit. If a customer is unable to pay the full amount of a deposit, the Company will accept payment of the deposit in installments over a period of not more than four (4) months. Upon disconnection of service and receipt of the final payment from the Customer, the Company shall refund the Customer's deposit plus accrued interest, or the balance, if any, in excess of the unpaid bills for service furnished by the Company. Interest on a Customer's deposit shall earn simple interest of three percent (3%) per annum. If a Customer has paid his bills for service for twelve (12) consecutive months by the due date for such bills, the Company will automatically refund the deposit plus accrued interest to the Customer.

(continued)

CONDITIONS FOR REFUSAL OR DISCONNECTION OF SERVICE

The Company may refuse or disconnect service for any of the following reasons:

(a) Customer has requested disconnection (the Company may require up to forty-eight hours' written notice).

(b) An unsafe service condition exists on the Customer's premises, which is likely to cause injury to person or property.

(c) An other condition of the Customer's premises makes it unsafe for the Company to perform work on such premises.

(d) Customer has a delinquent service bill, and the Company has provided proper notice.

(e) Customer has failed to provide credit information, pay a security deposit, pay an additional deposit, or provide a guarantee.

(f) Customer has failed to comply with any of the provisions of the applicable Company tariff.

(g) Customer has failed to comply with interruption or curtailment orders issued by the Company.

(h) Customer is indebted to the Company for past bills incurred and refuses to liquidate the debt.

(i) Customer, although not personally liable to the Company, is attempting to return service to an indebted household and no attempts are forthcoming to liquidate the debt of that household. An indebted household exists when the person applying for service (1) was a member of the household when the prior debt was incurred by someone else living in that household, whether at the same address or at a new one, or (2) has moved into the same apartment or building in which the prior bill was incurred, and the person who owes the debt is still living there.

(j) A connection, device, or bypass is found on the meter, regulating equipment, or piping of the Customer which prevents the meter from properly registering consumption, or a meter is found with broken seals or otherwise shows evidence of tampering.

(k) Customer has otherwise received the benefit of service with respect to the account or has been guilty of fraud or misrepresentation with regard to service.

(l) Customer refuses to allow authorized Company personnel onto the Customer's premises for purposes of examining the piping, appliances, and other equipment relating to the Company's service; reading the meter, ascertaining connected loads to turn on service, obtain an actual meter reading, to inspect a suspected safety problem, or to perform maintenance work.

(m) Any other reason where authority is specifically granted by Nebraska statute or applicable administrative rule.

(continued)

GENERAL TERMS AND CONDITIONS
(continued)

DISPUTE RESOLUTION

Pursuant to the provisions of Revised Statutes of Nebraska, 1996 Reissue, Sections 70-1608 through 70-1614, a Customer may request a conference in regard to any dispute over a proposed disconnection of service with the Company. A designated employee of the Company will hear and decide all matters related to the dispute. If a residential Customer disputes the proposed disconnection of service and provides a written statement to the Company setting forth the reasons for the dispute and the relief requested, a conference shall be held between the Company and the Customer before service will be disconnected. Upon receipt of such a written statement, the Company will notify the Customer, in writing, of the time, place, and date scheduled for the conference, which shall be within fourteen (14) days of the Customer's request. At such conference, the employee designated by the Company to hear such dispute, shall, based solely upon the evidence presented, affirm, reverse, or modify any Company decision involving the disputed bill. The employee shall allow termination of utility service only as a measure of last resort after he has exhausted all other remedies less drastic than termination. The Customer may appeal an adverse decision of the Company employee to a management office of the Company, and a hearing will be held to resolve the dispute. At such hearing, the Customer may be represented by legal counsel or other representative or spokesperson, examine the Company's files and records pertaining to all matters directly relevant to the dispute or utilized by the Company in reaching the decision to propose termination, present witnesses and offer evidence, confront and cross-examine witnesses, and make or have made a record of the proceedings at his own expense.

Budget Payment Plan

The Company's Budget Bill Plan (BBP) is available to residential and commercial customers. It may be initiated for a customer at any time during the year, provided that the customer has paid all outstanding utility charges due the Company.

The company will have a billing practice under which a Customer may be billed monthly for a percentage or portion of the Customer's total annual consumption as estimated by the Utility. The purpose of such budget billing is to provide, insofar as it is practicable to do so, a uniform monthly bill.

Each BBP account will be reviewed by the Company at least semi-annually, based on their Budget Billing start date, to determine if an adjustment to the budget amount is necessary, to minimize annual over/under collection balances. The new BPP will be determined by adding the customers actual debit or credit balance, at the time of review, to the customer's prior 12 months billings under current tariff rates, adjusted for normal weather, known changes in consumption, and projected Adjustment Clause price increases or decreases, the sum of which is divided by twelve. Where prior billings are not available, the Company will estimate billings using the best available information of customer's consumption.

Should a customer request that the Company not take the actual debit or credit balance into consideration when calculating a revised budget amount, the Company will issue a check to a customer with a credit balance or bill the customer for any debit balance.

Service to customers participating in the BPP shall be pursuant to the General Terms and Conditions of service including the Terms of Payment provisions contained therein, provided, however, that service to a BBP customer will not be disconnected for non-payment if the customer has a credit balance in his account. A customer may discontinue participation in the BBP at any time.

~~BUDGET PAYMENT PLAN~~

~~The Company's Budget Payment Plan (BPP) is available to residential and commercial customers. It may be initiated for a customer at any time during the year, provided that customer has not discontinued a previous BPP with the Company within the last twelve (12) months, and has paid all outstanding utility charges due the Company~~

~~The customer's initial budget amount will be determined according to the following formula:~~

$$\cancel{BP = \frac{A}{(B - .5)}}$$

~~Where BP = the monthly budget amount~~

~~A = the estimated total billing, adjusted for anticipated rate changes and weather variances, from the date the BPP becomes effective until~~

~~(continued)~~

Section No. 4
Original Sheet No. 6
Canceling Sheet No.

~~GENERAL TERMS AND CONDITIONS~~
~~(continued)~~

~~the annual review date in June. This amount shall include not only utility amounts, but also taxes, other contracted purchases, etc.~~

~~B = the number of monthly billings to be received by the customer between the BPP effective date and the annual review date.~~

~~Each BPP account will be reviewed by the Company at various times during the year to determine if an adjustment to the budget amount is necessary and after the customer's June billing.~~

~~A customer's revised budget amount will be determined according to the following formula:~~

$$\cancel{BP = \frac{A}{B} + \frac{C}{B}}$$

~~Where BP, A, and B are defined as above~~

~~C = customer's actual debit or credit balance at the time of review.~~

~~Should a customer request that the Company not take the actual account balance into consideration when calculating a revised budget amount, the Company will issue a check to a customer~~

~~with a credit balance or bill the customer for any debit balance. A customer may discontinue participation in the BPP at any time.~~

~~Service to customers participating in the BPP shall be pursuant to the General Terms and Conditions of service including the Terms of Payment provisions contained therein, provided, however, that service to a BPP customer will not be disconnected for non-payment if the customer has a credit balance in his account.~~

PEAK SHAVING GAS SUPPLIES

The Company may supply gas from any stand-by equipment provided that the gas so supplied shall be reasonably equivalent to the natural gas normally supplied hereunder.

RESALE PROHIBITED

All gas purchased under any rate schedule shall not be resold by the purchaser thereof in any manner.

(continued)

GENERAL TERMS AND CONDITIONS
(continued)

SERVICE LINE INSTALLATION

For services, except mobile homes in mobile home parks, the Company will install a service along the shortest feasible route from the gas main to the customer's building upon the customer making a non-refundable contribution based upon the distance from the customer's property line to the point of service attachment as follows:

~~Size of Service Pipe~~	~~Non-Refundable Contribution for Up to 150'~~	~~Non-Refundable Contribution Per foot for Additional Pipe~~
~~1/2", 3/4", 1 1/4"~~	~~$ 90.00~~	~~$1.00~~
~~2"~~	~~$175.00~~	~~$1.50~~
~~Larger than 2"~~	~~$300.00~~	~~Company's current cost of installed pipe~~

For residential customers using natural gas as their primary heating source and for water heating: the customer will be charged a $90.00 connection fee for the first 150 feet of service pipe. Any distance beyond 150 feet may result in the company requiring an Advance for Construction or a Contribution in Aid of Construction based on the consideration of revenues from the project and the cost of the construction.

For residential customers using natural gas for space heating only, fireplace only, water heating only, natural gas grill only, or any combination other than primary space heating and water heating as described above: the Company will consider the total cost of serving the Customer and the expected revenue from the Customer. In this determination, if the project is not economically feasible, the Company may require an Advance for Construction or a Contribution in Aid of Construction from the customer to aid in the construction expense to serve the Customer.

(Continued)

For services to mobile homes in mobile home parks, a non-refundable contribution of $75.00 will be made by the customer for services up to 50 feet of horizontal piping in the mobile home lot. For service over 50 feet, or where the load does not consist of a natural gas furnace and a natural gas water heater, an additional non-refundable contribution may be required as described in the preceding paragraph.

Commercial and Industrial Customers: The Company may install natural gas service or main without charge where the Company deems the anticipated revenue from the customer is sufficient to justify the service or main extension. The Company will apply the general principle that the rendering of natural gas service to the applicant shall be economically feasible so that the cost of extending such service will not have an undue burden on other customers. In determining whether the expenditure of natural gas service or main is economically feasible, the Company shall take into consideration the total cost of serving the Customer and the expected revenue from the Customer. If the Company determines that the extension of service or main to the Customer is not economically feasible, the Company may require an Advance for Construction or a Contribution in Aid of Construction from the customer or customers to aid expansion. In instances where the project is not paid in advance, the Company may require a Letter of Credit or other Guarantee to secure the cost of the project. Projects that term longer than one year will carry interest at the rate of the allowed rate of return in the Company' most recent gas cost of service determination.

In instances where a Contribution in Aid of Construction is required, three years after the project has been completed, the Company will have the option to review the three-year average use. If the actual volumes vary from projected volumes by 20% or more, the Company has the option to charge or credit the customer for the variance, without interest, in projected Contribution in Aid of Construction.

Installation of gas service lines are scheduled by the Company for completion during the regular construction season. The Company may make a charge for added cost of the construction of a gas service line if the installation is required other than during the regular construction season.

The Company will not install Gas Services and Mains until the surface has been graded to within six inches of a permanent established elevation.

For services to mobile homes in mobile home parks, a non-refundable contribution of $75.00 will be made by the customer for services up to 50 feet of horizontal piping in the mobile home lot, and an additional non-refundable contribution of $1.00 will be made by the customer for each additional foot.

BILLING DAY AND CURTAILMENT OF GAS

The billing day for the purpose of determining the amount of gas used will be from 9:00 a.m. CCT (Central Clock Time) one day until 9:00 a.m. CCT the next day. The Company shall have the right to curtail or limit the Customer's use of gas during any billing day to the Contract Demand then in effect when demand by firm and higher priority interruptible natural gas purchasers exceeds available pipeline supply. Curtailment of interruptible gas will commence at 9:00 a.m. CCT at the start of a new billing day. Under normal circumstances, notice of curtailment of interruptible gas will be given to Customer by 3:00 p.m. CCT, prior to the beginning of the gas day in which curtailment is to begin. However, in cases of emergency (to be determined solely by the Company) any notice prior to 9:00 a.m. CCT is deemed to place the curtailment in effect at 9:00 a.m. CCT, and such curtailment shall continue in effect until the Company notifies Customer that the curtailment is released. In cases of emergency when notice of curtailment cannot reasonably be given immediately prior to a new billing day, Customer will cooperate with the Company by curtailing its use of interruptible gas as soon as possible after notice of curtailment by Company. Proper notice of curtailment will be deemed to have been given when any person or persons authorized to receive curtailment orders on behalf of Customer has been notified by telephone or in person by a representative of Company.

(continued)

The Company will endeavor to give the Customer as much notice as possible with respect to curtailment of service. Customer agrees to provide and maintain complete standby facilities and have available at all times sufficient standby fuel to maintain continuous plant operations during complete curtailment in the delivery of natural gas.

CONTINUITY OF SERVICE, INTERRUPTIONS, AND LIABILITY

The Company will endeavor to provide continuous service but does not guarantee an uninterrupted or undisturbed supply of gas service. The Company will not be responsible for any loss or damage resulting from the interruption or disturbance of service for any cause other than negligence of the Company. The Company will not be liable for any loss of profits or other consequential damages resulting from the use of service or any interruption or disturbance of service.

The Company shall use due care and diligence to furnish gas service near the normal pressure levels and in accordance with the acceptable levels of delivery pressure as may exist under operating conditions in the pipeline and distribution system. Because delivery pressure may vary, the customer shall install, operate, and maintain, at his own expense such pressure regulating devices as may be necessary to regulate the pressure of gas after its delivery to the customer. The Company shall not be liable for the control of gas pressure or gas after delivery of gas to the consumer.

Neither Customer nor the Company shall have any claim against the other for damages sustained as a result of interruptions of gas deliveries caused by Acts of God, weather conditions, labor disturbances, fires, accidents, breakage or repair of pipeline, mechanical failure of any machinery, equipment or other mechanical devices, shortage of gas supply, or other causes or contingencies beyond the reasonable control of and occurring without negligence on the part of such other party. When such causes or contingencies cease to be operative, delivery and receipt of gas shall resume as soon as practicable. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the party affected. Any such cause or contingency, however, exempting customers from liability for non-performance (except where prevented by valid orders or requirements of Federal, State, or other governmental regulatory bodies having jurisdiction in the premises) shall not relieve customer of its obligation to pay minimum charges in accordance with the applicable rate schedule.

The Customer agrees to save, indemnify and hold the Company harmless from any and all claims, damage, or injury to persons or property arising from any cause whatsoever after the delivery of gas by the Company to the point of service attachment, except where such injury or damage is shown to have

(continued)

GENERAL TERMS AND CONDITIONS
(continued)

been caused solely by the negligence of the Company. The Customer shall not be liable for any loss, damage, or injury to persons or property arising from any cause whatsoever before the actual delivery of gas to the point of service attachment, except where such injury or damage is shown to have arisen solely from the negligence of the Customer. The Customer assumes all responsibility for all service and equipment at and from the Customer's point of service attachment of such service, and will protect and save the Company harmless from all claims for injury or damage to persons or property occurring by such services and equipment, except where said injury or damage is shown to have been occasioned solely by the negligence of the Company.

DELIVERY PRESSURE

The volume of gas measured, where delivered at other than 0.25 p.s.i.g. at the customer's meter, shall be adjusted to a base pressure equal to 14.73 p.s.i.a. in accordance with accepted standards for measurement of gas at varying pressures.

METER ACCURACY AND TESTING OF METERS

A Customer may request the Company to test his meter, and the Company will make the test as soon as practical after the request. If a request is made within one year after a previous request, the Company may require a Customer to pay a reasonable deposit for the test. The deposit will be refunded if the meter is found to have an error of more than two percent (2%) fast, and the Company will refund to the Customer the percentage of the inaccuracy of the billed amount for the period equal to one-half the time elapsed since the most recent test, but not to exceed six (6) months. If the meter is found to have an error of more than two percent (2%) slow, the Company may bill the Customer for the percentage of the inaccuracy of the billed amount for the period equal to one-half the time elapsed since the most recent test, but not to exceed six (6) months.

PRIORITY OF SERVICE

All Customers will be classified according to priorities. The Company may require curtailments of natural gas at any time in order to protect deliveries of natural gas having a higher priority. The Company shall have the right to curtail use of natural gas in any community due to capacity limitations of facilities of either the pipeline supplier or the Company, even though service is continued for lower priority customers in another community. When the Company is unable to supply the full natural gas requirements of all its customers, curtailment of natural gas service will progress in the following sequence: Priorities 4, 3, 2 and 1. The Company, at its discretion, shall have the right to curtail / interrupt based on other operational factors.

(continued)

GENERAL TERMS AND CONDITIONS
(continued)

Priority 1: Firm residential and small commercial requirements less than 500 therms on a peak day. Curtailment within this priority will, where operationally possible, be on a pro rata basis.

Priority 2: Firm commercial requirements from 500 through 1,999 therms on a peak day, and industrial requirements from 0 through 1,999 therms on a peak day. Curtailment within this priority will, where operationally possible, be on a pro rata basis.

Priority 3: Firm commercial and industrial requirements greater than 2,000 therms on a peak day. Curtailment within this priority will, where operationally possible, be on a pro rata basis.

Priority 4: Interruptible commercial and industrial requirements. The Company may curtail a customer's usage regardless of priority if the customer elects to take interruptible service. Curtailment, where possible, will be ordered on the basis of lowest to highest non-gas margin regardless of jurisdiction or end-use.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF NEBRASKA

IN RE:	)	
	)	Docket No. NG-____
NORTHWESTERN CORPORATION,	)	
d/b/a NorthWestern Energy	)	

DIRECT TESTIMONY OF MICHAEL J. HANSON
ON BEHALF OF NORTHWESTERN ENERGY

Q. Please state your name and business address for the record.

A. Michael J. Hanson, 125 S. Dakota Avenue, Sioux Falls, South Dakota 57104.

Q. By whom are you employed and in what position?

A. I am employed by NorthWestern Corporation, dba NorthWestern Energy, ("NorthWestern" or "Company") as its President and Chief Executive Officer.

Q. Please describe your education and business experience.

A. I have been the President and Chief Executive Officer for the Company since March of 2005. I served as President and CEO of NorthWestern Public Service beginning in May 1998 until becoming Chief Operating Officer of NorthWestern Corporation from August 2003 to March 2005 and served as its President from March 2005 until May 2005 when I was named as the CEO as well. I was employed seventeen years with Northern States Power in a variety of positions before coming to NorthWestern. I was General Manager and CEO of NSP – South Dakota from 1994-1998. I attended the United States Naval Academy from 1977-79 and graduated from the University of Wisconsin in 1982 with a Bachelor of Science in accountancy. I received a Juris Doctor degree from William Mitchell College of Law in 1989. Exhibit (MJH-1) contains a listing of my education and business experience.

Q. What is the purpose of your prepared direct testimony?

A. In my prepared direct testimony, I will describe NorthWestern's rate filing and an overview of why NorthWestern is proposing an increase in its natural gas distribution rates at this time.

Q. Please describe the organization and operation of NorthWestern.

A. NorthWestern is an electric and gas distribution utility operating in the states of Nebraska, South Dakota, and Montana. Since NorthWestern's last natural gas rate filing in 1999, NorthWestern acquired the electricity and natural gas transmission and distribution assets and natural gas storage assets of the former Montana Power Company in February 2002. NorthWestern is an electric transmission and distribution utility in Montana, as it does not own generation. In South Dakota, NorthWestern is a vertically integrated electric utility. In both South Dakota and Nebraska, NorthWestern is a gas distribution and transmission utility. Natural gas services are provided to approximately 41,300 customers in four communities in Nebraska (North Platte, Kearney, Alda and Grand Island). NorthWestern also serves 110 electric and 60 gas South Dakota communities with approximately 42,500 gas and 59,250 electric customers in its South Dakota service territory. NorthWestern provides electric services to 322,000 customers in 187 communities in MT while its natural gas business serves 174,000 customers in 105 communities.

Q. What is the purpose of this rate filing?

A. The purpose is to request a rate adjustment that will allow NorthWestern the opportunity to earn an appropriate return on the Company's natural gas operations in Nebraska. NorthWestern last filed for a rate increase in 1999. Since that filing, NorthWestern has experienced increased costs in operating its natural gas utility due to inflation and additional federal government regulations regarding natural gas utility operations.

NorthWestern is also seeing the effect of decreased revenue generation from residential customers while its costs to do business continue to increase. As residential customers become more knowledgeable about energy efficiency, replace older heating equipment with more efficient models, or make the switch to electric heating, the basic costs of maintaining utility infrastructure remain while trying to recover those costs through decreased use of natural gas – directly impacting NorthWestern's rate recovery mechanism. This phenomenon is further highlighted when consideration is given to weather normalizing our rate revenues. For example, when weather normalizing rate revenues from 1998 to present day to reflect normal Heating Degree Days, there is a decrease of 7 million therms in natural gas residential usage from 1998 to 2006.

Q. Please describe the rate increase request?

A. NorthWestern proposes an increase in natural gas distribution rates of approximately 5.48%. Details of the proposed rates and charges are shown in the filed revised tariff schedules as described in the direct testimony and exhibits of Jeff Decker.

Q. Please describe NorthWestern's customer notification of the proposed increase.

A. Simultaneous with the filing of NorthWestern's Application for a natural gas rate adjustment with the Nebraska Public Service Commission, letters will be sent to each community notifying them of the natural gas rate application filing with the NPSC and NorthWestern's intention to negotiate directly with each of the Affected Cities. Included with the notification letters will be copies of the Application with the Nebraska Public Service Commission in electronic format for each community's use.

Additionally, NorthWestern will post a notice of proposed increase in all of its offices. On the date of submittal for the Application with the Nebraska Public Service Commission, a release will be issued to the news media. Each customer will be mailed a postcard in May with the following information:

- notification of the natural gas rate filing with the Nebraska Public Service Commission and that notification of the natural gas rate filing has been served to each Nebraska community's city office;
- a description of our request to negotiate directly with the Nebraska communities on behalf our customers; and,
- how they can view the proposed rate changes can be viewed at our local offices, on NorthWestern's website (www.northwesternenergy.com), or at the Nebraska Public Service

Commission's website (www.psc.state.ne.us).

After final approval of rates by the Nebraska Public Service Commission, a notice will be mailed to all Nebraska natural gas customers informing them of any rate changes approved by the Commission. Copies of any approved rate increase will also be available at NorthWestern's local offices and its website will be updated to appropriately reflect any approved rate changes.

Q. Please explain NorthWestern's approach to serving its Nebraska customers.

A. NorthWestern is committed to meeting the natural gas needs of business and non-business people in Nebraska. NorthWestern will continue to work with all customers to add growth and value to their operations and the economic well being of Nebraska.

Q. What is NorthWestern doing to improve customer service and increase system efficiency and reliability?

A. NorthWestern is constantly searching for ways to improve service to its customers. Furthermore, NorthWestern continuously surveys its customers to determine what can be done to enhance the value of our services. Finally, NorthWestern is constantly reviewing its processes and procedures. This constant evolution will enable NorthWestern to anticipate and meet changes in the utility industry. These are ongoing efforts that will be reviewed continually and enhanced with modern technology.

Q. Does that conclude your prepared direct testimony?

A. Yes, it does.

Michael J. Hanson
Education and Work Experience Synopsis

MICHAEL J. HANSON
47258 272nd Street
Sioux Falls, South Dakota 57108

Position:	President & CEO NorthWestern Corporation	
Date Effective:	May 2005	
Job History:	2004-2005	NorthWestern Corporation – Chief Operating Officer
	2002-2003	NorthWestern Energy – President & CEO
	2000-2002	NorthWestern Services Group – President & CEO
	1998-00	NorthWestern Public Service - President & CEO
	1994-98	Northern States Power - General Manager & Chief Executive
	1989-94	Northern States Power - Attorney
	1984-89	Northern States Power - Internal Auditor
	1983-84	Northern States Power - Accountant
	1981-83	Northern States Power - Accounting Coordinator
	1981-82	Northern States Power - Gas Operating Clerk
Birth:	December 12, 1958 Sparta, Wisconsin	
Military Service:	Navy, 1977-1979 Midshipman (W-4)	
Education:	Sparta Senior High School, 1977 United States Naval Academy, 1977-79 University of Wisconsin, 1982, BS William Mitchell College of Law, 1989, Juris Doctor	
Family:	Married Laura K. Eggers, Sparta, Wisconsin, February 16, 1980 Children - Justin M. Hanson - born May 25, 1982 Danielle M. Hanson - born March 19, 1985	
Directorships:	- South Dakota Rural Enterprises, Inc. (1998-1999 & 2001-Present)	

- South Dakota Electric Utility Companies (Chairman) (1994 – Present)
- Sioux Falls Development Foundation (1994-1998) & (2000-Present)
- Sioux Council Boy Scouts Board (1994-2002) (President/1999-2000)
- Fargo Cass County Economic Development Corp (1997-1998)
- Sioux Vocational Services (1994-1997)
- Sioux Empire United Way (1994-1997)
- Huron Regional Medical Center Foundation Board (Vice Chairman) (1999-2001)
- Marquette Bank - Sioux Falls (1994-2001)

Club and Association Memberships:

- Edison Electric Institute
- Minnesota State Bar Association
- Hennepin County Bar Association
- American Bar Association
- Institute of Internal Auditors
- North East Council of Governments
- Downtown Rotary Club, Sioux Falls
- Gloria Dei Lutheran Church

Recognitions:

- Juris Doctor Magna Cum Laude (1989)
- Certificate of Excellence – Certified Internal Auditor Exam (1984)
- James R. Kelly Award (CIA Exam) (1984)
- Daughters of the American Revolution Good Citizenship Award (1977)

AFFIDAVIT

STATE OF SOUTH DAKOTA)
) ss
COUNTY OF MINNEHAHA)

I, Michael J. Hanson, being first duly sworn on oath, do depose and state that I have read this document and am familiar with the contents thereof and the same are true to the best of my knowledge and belief.

FURTHER THE AFFIANT SAYETH NOT.

Michael J. Hanson

Subscribed and sworn to before me this 1 day of May, 2007.

Notary Public in and for the State of South Dakota
Commission Expires: January 30, 2009

CORINNE BOHRER
NOTARY
SEAL
PUBLIC
SOUTH DAKOTA

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF NEBRASKA

IN RE:	)	
	)	Docket No. NG-___
NORTHWESTERN CORPORATION	)	
d/b/a NorthWestern Energy	)	

PREFILED DIRECT TESTIMONY OF KENDALL G. KLIEWER
ON BEHALF OF NORTHWESTERN ENERGY

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Witness Information

Q. Please state your name and business address.

A. Kendall Kliewer, 125 South Dakota Avenue, Sioux Falls, South Dakota, 57104.

Q. By whom are you employed and in what capacity?

A. I am the Vice President and Controller of NorthWestern Corporation (NWE or NorthWestern).

Q. Please summarize your educational and employment experiences.

A. I have been the Chief Accountant of NorthWestern since November 2002, the Controller since July 2004 and a Vice President since August 2006. My primary responsibilities include, among other duties, overseeing compliance with financial reporting requirements established by the Securities and Exchange Commission (SEC) and other regulatory agencies, technical research with regard thereto, reviewing NWE's financial statements, and implementing and overseeing accounting policies and procedures. Previously, I was a Senior Manager at KPMG LLP in Lincoln, Nebraska. I was employed by KPMG from September 1996 through September 1998 and again from October 1999 through November 2002, when I joined NorthWestern. During my tenure at KPMG, I coordinated financial statement audits, consulted clients on appropriate accounting practices and SEC reporting requirements, assisted clients with the preparation and review of various SEC filings, and planned and supervised audits. From September 1998 through October 1999, I was the Vice President – Regulatory Reporting Accountant, of TierOne Bank in Lincoln, Nebraska, where I was responsible for the preparation and review of various regulatory reports requiring a working knowledge of regulatory accounting principles, generally accepted accounting principles and income tax reporting requirements. I have a Bachelor of Science in Business Administration from the University of Nebraska and am a certified public accountant.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. My testimony:

1. Provides background for any changes in the accounting function since the last rate filing on November 2, 1999;

2. Discusses NorthWestern's method of allocating shared administrative costs;
3. Presents a detailed explanation of various adjustments to the income statement provided in this filing; and
4. Discusses cash working capital requirements.

Changes in the Accounting Function

Q. What has changed since the last rate filing?

A. NorthWestern has experienced many changes since the last rate filing. The most significant are as follows:

- Acquisition of Montana Power Utility Assets;
- Implementation of a new SAP Software System; and,
- Use of Fresh-Start Reporting due to NorthWestern's Bankruptcy.

Acquisition Montana Power Utility Assets

On February 15, 2002, we completed the asset acquisition of the former Montana Power Company's (Montana Power) energy transmission and distribution business. As a result of the acquisition we have adopted new methods of allocating administrative costs as further described below.

Implementation of a new SAP Software System

In July 2002, we replaced our previous general accounting system with SAP, a fully integrated enterprise-wide accounting software system. Through this system, our primary chart of accounts consists of a "natural chart of accounts" (NCOA) for SEC and internal reporting purposes, with an automated conversion to the Uniform System Chart of Accounts (USCOA) for regulated reporting purposes, including the Federal Energy Regulatory Commission (FERC), and the Nebraska Public Service Commission. The NCOA contains transactional detail in the Controlling (CO) Module through cost objects such as profit centers, cost centers and orders. This data is summarized and translated into FERC accounts through specialized FERC module configuration in SAP, as transactions cannot be posted directly to FERC accounts. The FERC module provides the ability to drill down from a FERC account into the CO Module to obtain the transactional detail.

<u>Use of Fresh-Start Reporting due to NorthWestern's Bankruptcy</u>

On September 14, 2003, we filed a voluntary petition for relief under the provisions of Chapter 11 of the Federal Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware. On October 19, 2004, the Bankruptcy Court entered an order confirming our Plan of Reorganization (Plan), which became effective on November 1, 2004.

In connection with our emergence from Chapter 11, effective the close of business on October 31, 2004, we applied fresh-start reporting under the American Institute of Certified Public Accountants (AICPA) Statement of Position (SOP) 90-7, *Financial Reporting by Entities in Reorganization Under* the Bankruptcy Code. The application of fresh-start reporting included the following:

- The reorganization value was allocated to the assets in conformity with the procedures specified by Statement of Financial Accounting Standards (SFAS) No. 141, Business Combinations. The enterprise value exceeded the sum of the amounts assigned to assets and liabilities, with the excess allocated to goodwill.
- Deferred taxes were reported in conformity with applicable income tax accounting standards, principally SFAS No. 109, Accounting for Income Taxes. Deferred taxes assets and liabilities were recognized for differences between the assigned values and the tax basis of the recognized assets and liabilities.
- Adjustment of our qualified pension and other postretirement benefit plans to their projected benefit obligation by recognition of all previously unamortized actuarial gains and losses.
- Reversal of all items included in other comprehensive loss, including recognition of the minimum pension liability, recognition of all previously

unrecognized cumulative translation adjustments and removal of a hedge gain associated with unsecured debt.

- Each liability existing as of the Plan confirmation date, other than deferred taxes, was recorded at the present value of amounts to be paid determined at our computed incremental borrowing rate.

Allocated Shared Administrative Costs

We have three regulatory jurisdictions consisting of Montana, South Dakota and Nebraska. In addition, we have unregulated electric operations consisting of our lease of a 30% share of Colstrip Unit 4 in Montana and unregulated natural gas operations consisting of gas supply and management services in South Dakota. Our administrative costs are allocated between jurisdictions and regulated and unregulated operations by utilizing a 3-factor formula, consisting of gross plant, labor, and revenue. The most recent jurisdictional allocation methodology is attached as Exhibit_(KGK-1).

In addition, we utilize a 4-factor formula to allocate shared costs between South Dakota electric and gas operations and Nebraska gas operations consisting of net plant in service, revenue, direct electric and gas expenses, and direct electric and gas payroll expense charged to O&M and construction. The most recent electric and gas allocation methodology is attached as Exhibit_(KGK-2).

Normalization Adjustments

Q. What are your explanations of the various adjustments to the income statement provided in this filing?

A. The following narrative discusses each of these items, which are reflected in Schedule No. 1.1:

Adjustment No. 3 – Rate Case Expense

Consistent with prior ratemaking treatment, we have included estimated rate case expense of $60,000 for this filing. This level of cost is proposed to be amortized into expense equally over a 5-year period.

Adjustment No. 4 – Merger and Acquisition (M&A) and Nonutility Costs

The vast majority of M&A and nonutility related costs are tracked in specific orders and excluded from the amounts in Column C of Schedule 1. We did identify various costs related to the merger, bankruptcy, and other nonutility items that were allocated to the jurisdictions and have been removed from this filing. These primarily consisted of year-end legal accruals, tax related services, aircraft expenses and Board of Director fees related to the merger.

Adjustment No. 5 – Advertising Expense

Consistent with prior ratemaking treatment, this adjustment was made to reflect the removal of known and measurable promotional and institutional advertising expense originally recorded as a utility operating expense.

Adjustment No. 6 – Labor Expense

Consistent with prior ratemaking treatment, actual base year labor allocated or directly charged to Nebraska operations was increased 3 percent, which is consistent with the average range of recent annual salary adjustments to employees.

Adjustment No. 7 – Interest Synchronization

Consistent with prior ratemaking treatment, this adjustment reflects the change in Federal income taxes by using the interest synchronization method of computing the interest deduction for income tax purposes. Under this method, interest in the income tax calculation was set to be equal to the implied interest in our proposed cost of capital included in this filing.

Adjustment No. 8 – Economic Development

We participate in program in which we provide annual contributions to the cities of Grand Island, Kearney, and North Platte to be used for economic development and growth purposes. This program was requested by these cities in the settlement of the 1999 rate case filing and we are requesting recovery of our annual contributions in this filing.

Adjustment No. 9 – Insurance Actuarial Adjustment

In December 2006, we decreased our self-insurance reserves based on an updated annual actuarial valuation. The following is the detail of this entry:

General liability	$ 14,378
Worker's compensation	$ 9,473
Automobile	$ 5,049

As this valuation includes factors that were not part of our normal course of business, this entry was reversed as a normalizing adjustment to the 2006 actual income statement.

Adjustment No. 10 – Association Dues

Consistent with prior ratemaking treatment, this adjustment was made to reflect the reassignment of association dues to ensure this filing only includes dues allocable to the Nebraska natural gas jurisdiction.

Adjustment No. 11 – Stock Grants

In late 2006, approximately 305,155 shares were granted under our stock-based incentive plan covering all non-officer employees. In addition, during 2006, NorthWestern's Board of Directors approved a long-term incentive plan covering officers and various management level employees of the company. As a result, this adjustment was to normalize the actual expense as if the shares were granted and the long-term incentive plan was approved at the beginning of the year and amortized on a straight-line basis over three years.

Adjustment No. 12 – IT Upgrade Labor

In 2006, we utilized internal labor to perform an upgrade on the SAP system. As these labor costs were capitalized as part of the software upgrade project, this adjustment was made to reflect a normalized level of labor expense.

Adjustment No. 13– Government Lobby Related Costs

Consistent with prior ratemaking treatment, this adjustment was made to reflect the removal of known and measurable government related costs originally recorded as a utility operating expense.

Adjustment No. 14 – Intra-Company Rent on Capitalized Common Assets

There are certain assets that have been capitalized by one regulatory jurisdiction but are used by all jurisdictions. These "common assets" are entirely associated with computer software programs and computer hardware equipment. For example, Montana Power initially purchased and implemented SAP in 2000. This software was in use upon the acquisition by NorthWestern and is now used as our enterprise-wide accounting system. Since these common assets are used across jurisdictions, the associated operating costs should also be shared among the jurisdictions. To that end, a rental charge has been established so that Nebraska is charged for using Montana common assets and Montana is charged for using Nebraska common assets. During 2005, we began separating the asset cost between jurisdictions, which removed the need for intra-company rental charges for assets placed in service after that date.

Adjustment No. 15 – Eliminate O&M Charged to Nekota

In 2006, we charged our unregulated business Nekota (pipeline) a management fee for the use of utility personnel. This charge covered supervision, engineering, and administrative people and was calculated using time studies. As Nekota has been merged into the utility, this management fee was eliminated and an adjustment was made to reflect a normalized level of labor expense.

Adjustment No. 16 – Depreciation Rate Change

NorthWestern had a depreciation study completed by Foster and Associates in 2006. This study covered the gas and common assets of South Dakota and Nebraska. The report presents a recommendation that NorthWestern adopt straight-line, vintage-group, remaining-life rates and record depreciation expense using primary account accrual rates that composite to 2.81 percent for gas operations and 5.14 percent for common plant used for both gas and electric operations.

Q. Does this complete your testimony?

A. Yes, it does.

NorthWestern Energy
2006 UTILITY ADMINISTRATION STUDY

Plant Allocation (000's Omitted)

	In-Service	CWIP	Common Plant	Gross Plant	Percent
MTU	1,596,464	15,987	0	1,612,451	74.81%
NPS	509,246	6,190	0	515,437	23.91%
CU4	26,721	744		27,465	1.27%
Total	**2,132,431**	**19,805**	**0**	**2,155,352**	**100.00%**

Source: SAP Trial Balance Account 160000-165999 MT12-100, SD12-100

Revenue

MTU	332,386	52.87%
NPS	199,516	31.74%
CU4	96,739	15.39%
Total	**628,642**	**100.00%**

Source: Historical Income by Segment (Profit Centers) MT01-100, SD01-100

Operating Labor Allocation (000's Omitted)

MTU	37,292	78.80%
NPS	10,031	21.20%
CU4	0	0.00%
Total	**47,323**	**100.00%**

Source: SAP Trial Balance Account 503000-503999

Allocation of Factors

Gross Plant:

	MTU	74.81%
	NPS	23.91%
	CU4	1.27%

Revenue:

	MTU	52.87%
	NPS	31.74%
	CU4	15.39%

Direct Labor:

	MTU	78.80%
	NPS	21.20%
	CU4	0.00%

	Plant	Revenue	Labor	Total	%
Total MTU	74.81%	52.87%	78.80%	206.48%	68.83%
Total NPS	23.91%	31.74%	21.20%	76.85%	25.62%
Total CU4	1.27%	15.39%	0.00%	16.66%	5.55%

NorthWestern Corporation, dba NorthWestern Energy
Electric and Gas Allocation of Shared Administrative Costs
December 31, 2006 Test Year

2006 Planned NPS Common Cost Allocations

To allocate the shared costs between SD Electric, SD Gas, and NE Gas, a 4 factor approach is utilized that is consistent with SD/NE PUC past methodolgy.

The factors utilized to allocate costs include:

1. Net Plant in Service - Electric and Gas
2. 12 month ended May 05 Revenue for Electric and Gas
3. Direct electric and gas expenses
4. Direct electric and gas payroll expense charged to O&M and Construction

The Factors are weighted equally to come up with the breakdown between electric and gas.

After this, the total gas percentage is broken out between SD and NE by applying their respective 4 factor percentage to the overall gas percent.

The 2006 planned allocations are as follows:

Electric	62%
SD Gas	20.90%
NE Gas	17.10%

Common Gas only costs are allocated between SD and NE as follows:

SD Gas	55%
NE Gas	45%

The methodology and results were developed by Jeff Decker and are consistent with past practices.

AFFIDAVIT

STATE OF SOUTH DAKOTA)
) ss
COUNTY OF MINNEHAHA)

I, Kendall Kliewer, being first duly sworn on oath, do depose and state that I have read this document and am familiar with the contents thereof and the same are true to the best of my knowledge and belief.

FURTHER THE AFFIANT SAYETH NOT.

Kendall Kliewer

Subscribed and sworn to before me this 1st day of May, 2007.

Nancy Thompson
Notary Public in and for the State of South Dakota
MCE 3/20/12

(SEAL)

NANCY THOMPSON
SEAL NOTARY PUBLIC SOUTH DAKOTA SEAL

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF NEBRASKA

IN RE:	)	
	)	**Docket No. NG-___**
NORTHWESTERN CORPORATION	)	
d/b/a NorthWestern Energy	)	

PREFILED DIRECT TESTIMONY OF PAUL J. EVANS
ON BEHALF OF NORTHWESTERN ENERGY

Q. Please state your name and business address.

A. Paul J. Evans. 125 S. Dakota Avenue, Sioux Falls, South Dakota 57104.

Q. By whom are you employed and in what capacity?

A. I am employed by NorthWestern Energy (NorthWestern or NWE) as the Treasurer.

Q. How long have you been employed in your current position?

A. I have been employed in my current position since June 2004.

Q. What are your responsibilities and duties in your current position?

A. I am responsible for the areas of cash management, corporate finance, insurance, credit, commodity risk management, rating agency and banking relationships.

Q. Please state your educational background and experience.

A. I have 16 years of experience within the fields of corporate finance, treasury, tax, audit and accounting. I have a Master of International Management from Thunderbird School of Global Management. I have a BBA from Stephen F. Austin State University with a major in Accounting. I also have my CPA certificate.

Q. What is the purpose of your testimony?

A. My testimony will discuss the capital structure, cost of debt, and cost of equity requested by NorthWestern in this proceeding. As a part of deriving the overall cost of capital, I am using the same rate of return on common equity recommended by Dr. Michael Vilbert from The Brattle Group for NorthWestern's South Dakota Gas Utility. I am also proposing to use the consolidated capital structure of NorthWestern Corporation and the cost of debt related to the Nebraska Gas Utility operations. Exhibit_(PJE-1) shows the components used in developing the required overall cost of capital.

Q. What are your conclusions?

A. The following is a summary of my conclusions regarding the overall cost of capital for the Gas Utility in Nebraska:

- The capital structure recommended is 48.54% debt and 51.46% equity;
- The cost of debt is 6.57%;
- The cost of equity is 11.25%;
- The rate of return is 8.98%;
- Allowing the Gas Utility to fully recover its cost of providing service will improve its financial performance and credit ratings, which over time should reduce capital costs and the rates paid by gas consumers.

This summary is shown on Exhibit_(PJE-1).

Q. Please explain the capitalization methodology that you have presented in this case.

A. The Company is proposing to use the consolidated capital structure of NorthWestern Corporation for the test year, which is calculated to be 48.54% debt and 51.46% equity. The Company believes using the consolidated capital structure will provide the best proxy of capitalization when comparing itself to other gas utility companies. The Company also looked at the ratio of its Nebraska Gas Utility allocated debt to its Nebraska Gas Utility rate base and calculated the ratio to be 49.0% debt and 51.0% equity. Furthermore, the Company looked at the Nebraska Gas Utility book capitalization, comprised of the Nebraska Gas Utility allocated debt and the book equity allocated to the Nebraska Gas Utility, and calculated the ratio to be 47.0% debt and 53.0% equity. Given that the consolidated capital structure is within the range of rate base and book capitalization, we believe that the consolidated capital structure is an accurate representation of the Nebraska Gas Utility capital structure.

Q. How did you determine the cost of debt?

For the long-term debt existing as of December 31, 2006, I determined all debt and capital lease obligations that are directly secured by assets of the combined Electric and Natural Gas Utilities in South Dakota and Nebraska. Because these obligations are linked to specific physical assets, it is straightforward to allocate them appropriately to NorthWestern's South Dakota and Nebraska utilities (see Exhibit_(PJE-2)). Since this is a gas rate case, I then excluded all pollution control bonds from the list of debt used to determine the gas utility's cost of debt.

I also excluded the capital leases on the James Valley and Great Plains pipelines, both of which are related to the South Dakota Gas Utility, and the lease on a vehicle used solely for the electric utility business. To derive the annual cost of long-term debt, I added the annual interest cost and the annual amortization of debt discount and issuance expense associated with each debt component (see Exhibit_(PJE-2)). By dividing the total annual cost of long-term debt by the long-term debt balance, I determined a cost of long-term debt of 6.57%.

Q. How did you determine the cost of equity?

A. NorthWestern has relied on the analysis performed by Dr. Michael J. Vilbert of The Brattle Group for the South Dakota Gas Utility. A copy of Dr. Vilbert's testimony is attached as Appendix A. Dr. Vilbert states that, in order to attract capital, NorthWestern must offer expected returns to investors that are consistent with returns provided by enterprises with similar business and risk characteristics. I believe that Dr. Vilbert's recommended cost of equity for the South Dakota Gas Utility is appropriate for the Nebraska Gas Utility given the two jurisdictions' similarity in business profile and regulatory environment. As such, I am using Dr. Vilbert's recommended 11.25% cost of equity.

Q. How did you determine the overall cost of capital required for the gas utility in Nebraska?

A. The overall cost of capital required for the Gas Utility in Nebraska is derived from the cost of long-term debt and cost of equity appropriate for the utility weighted by the percentage of debt and equity in the proposed consolidated capital structure. The balances and relative proportions for each component of the capital structure and the calculation of the weighted average cost of capital are shown on Exhibit_(PJE-1). As indicated on the exhibit, the weighted average cost of capital is 8.98%.

Q. Does this complete your prepared direct testimony?

A. Yes, it does.

NorthWestern Corporation, dba NorthWestern Energy
Nebraska Rate Case
Capital Structure and Rate of Return - Consolidated
December 31, 2006 Test Year

Line No.	Description	Amount	Percent of Capitalization	Rate		Rate of Return
	(a)	(b)	(c)	(d)		(e)
1	Long-Term Debt	700,604,448	48.54%	6.57%		3.19%
2	Common Equity	742,771,580	51.46%	11.25%	*	5.79%
3	Total	144,337,603	100.00%			8.98%

Per Mike Vilbert of The Brattle Group

NorthWestern Corporation, dba NorthWestern Energy
Nebraska Rate Case
Weighted Average Cost of Debt Capital
December 31, 2006 Test Year

Line No.			(1) Issue Title	(2) Issue Date	Maturity Date	(3) Interest Rate	(4) Principal Amount	Gross Proceeds	(5) Net Amount	(6) Per$100	(7) Currently Outstanding	(8) Yield to Maturity	Annual Interest Cost	Amortization of Debt Disc Premium and Expense	Total Cost	Weighted Average Cost
1	MT	FMB	6.04% Series, Due 2016	9/13/2006	9/1/2016	6.040%	150,000,000	149,926,500	148,426,500	98.951	149,928,950	6.043%	9,060,000	232,318	9,292,318	6.20%
2	SD/NE	FMB	7.00% Series, Due 2023	8/15/1993	8/15/2023	7.000%	55,000,000	55,000,000	53,827,052	97.867	55,000,000	7.000%	3,850,000	39,593	3,889,593	7.07%
3	SD/NE	SSN	5.875% Sr Notes ($225M), Due 2014	11/01/2004	11/01/2014	5.875%	64,000,000	64,000,000	62,687,860	97.950	64,000,000	5.875%	3,760,000	170,094	3,930,094	6.14%
4	MT	SSN	5.875% Sr Notes ($225M), Due 2014	11/01/2004	11/01/2014	5.875%	161,000,000	161,000,000	157,699,148	97.950	161,000,000	5.875%	9,458,750	475,913	9,934,663	6.17%
5	MT	PCB's	4.650% Series, Due 2023	04/28/2006	08/01/2023	4.650%	170,205,000	170,205,000	164,458,673	96.624	170,205,000	4.650%	7,914,533	553,322	8,467,855	4.98%
6	SD	PCB's	5.900% Grant Co I Due 2023	06/01/1993	06/01/2023	5.900%	6,400,000	6,400,000	6,179,805	96.559	6,400,000	5.900%	377,600	7,340	384,940	6.01%
7	SD	PCB's	5.900% City of Salix Due 2023	06/01/1993	06/01/2023	5.900%	4,000,000	4,000,000	3,779,805	94.495	4,000,000	5.900%	236,000	7,423	243,423	6.09%
8	SD	PCB's	5.850% Mercer Co Due 2023	06/01/1993	06/01/2023	5.850%	7,550,000	7,550,000	7,329,805	97.084	7,550,000	5.850%	441,675	7,423	449,098	5.95%
9	SD	PCB's	5.900% Grant Co II Due 2023	06/01/1993	06/01/2023	5.900%	3,400,000	3,400,000	3,179,805	93.524	3,400,000	5.900%	200,600	7,423	208,023	6.12%
10	SD	C.Lease	NPS Capital Leases				7,820				7,820		526		526	6.73%
11	MT	C.Lease	MTU Capital Leases				39,315,744				39,315,744		3,041,909		3,041,909	7.74%
12	SD	C.Lease	NEK Capital Lease				1,059,543				1,059,543		108,328	0	108,328	10.22%
13			Credit Facility Borrowings	Various	11/1/2009		50,000,000				50,000,000		3,250,000	1,414,380	4,664,380	9.33%
14	MT		GFT Debt				$27,556,984				27,556,984		1,720,236	117,037	1,837,273	6.67%
15			**Total Consolidated Long-Term Debt**								$739,424,040		$43,420,157	$3,032,266	$46,452,423	6.28%
			Less:													
16	MT	C.Lease	Basin Creek Power - Capital Lease								38,819,592		3,008,518		$3,008,518	7.75%
17			**Adjusted Long-Term Debt**								$700,604,448		$40,411,639	$3,032,266	$43,443,905	6.20%
19			**NE ONLY Long-Term Debt**				$119,000,000	$119,000,000	$116,514,912		$119,000,000		$7,610,000	$209,687	$7,819,687	6.57%

Note: Consolidated long-term debt excludes the Basin Creek Power purchase agreement classified as a capital lease per FAS 13 for the consolidated capital structure.

AFFIDAVIT

STATE OF SOUTH DAKOTA)
) ss
COUNTY OF MINNEHAHA)

I, Paul J. Evans, being first duly sworn on oath, do depose and state that I have read this document and am familiar with the contents thereof and the same are true to the best of my knowledge and belief.

FURTHER THE AFFIANT SAYETH NOT.

Paul J. Evans

Subscribed and sworn to before me this 1st day of May, 2007.

Notary Public in and for the State of South Dakota

MCE 9.13.2012

APPENDIX A

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

IN RE:	)	
	)	Docket No. NG07-___
NORTHWESTERN CORPORATION	)	
d/b/a NorthWestern Energy	)	

PREFILED DIRECT TESTIMONY OF

MICHAEL J. VILBERT

ON BEHALF OF

NORTHWESTERN CORPORATION

CONCERNING

COST OF EQUITY

FOR

NORTHWESTERN CORPORATION'S

SOUTH DAKOTA GAS UTILITY

APRIL 26, 2007

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I. INTRODUCTION AND SUMMARY

Q1. Please state your name and address for the record.

A1. My name is Michael J. Vilbert. My business address is The Brattle Group, 44 Brattle Street, Cambridge, MA 02138, USA.

Q2. Please describe your job and your educational experience.

A2. I am a Principal of The Brattle Group, ("Brattle"), an economic, environmental and management consulting firm with offices in Cambridge, Washington, London, San Francisco and Brussels. My work concentrates on financial and regulatory economics. I hold a B.S. from the U.S. Air Force Academy and a Ph.D. in finance from the Wharton School of Business at the University of Pennsylvania.

Q3. What is the purpose of your testimony in this proceeding?

A3. I have been asked by NorthWestern Energy Corp. ("NorthWestern" or the "Company") to estimate the cost of equity that the Public Utilities Commission of the State of South Dakota (the "Commission") should allow NorthWestern an opportunity to earn on the equity financed portion of its South Dakota gas utility assets, which provide retail gas distribution service in South Dakota.

To accomplish this task, I estimate the overall cost of capital for a sample of regulated natural gas local distribution companies ("LDCs") using the discounted cash flow ("DCF") and risk positioning models. I then evaluate the relative business and financial risk of NorthWestern's South Dakota natural gas operations ("NorthWestern's SD operations") to the gas LDC sample. These comparisons are important in determining my recommended cost of equity for a regulatory capital structure with 51.5 percent equity, which is the percent equity in the Company's proposed capital structure in this proceeding.

Q4. Please summarize the parts of your background and experience that are particularly relevant to your testimony on these matters.

A4. Brattle's specialties include financial economics, regulatory economics, and the gas and electric industries. I have worked in the areas of cost of capital, investment risk and related matters for many industries, regulated and unregulated alike, in many forums. I have testified or filed cost of capital testimony before the Federal Energy Regulatory Commission, the Arizona Corporation Commission, the Pennsylvania Public Utility Commission, the Public Service Commission of West Virginia, the Tennessee Regulatory Authority, the Canadian National Energy Board, Alberta Energy and Utilities Board, the Ontario Energy Board, and the Labrador & Newfoundland Board of Commissioners of Public Utilities. I have not previously testified before this Commission. Appendix A contains more information on my professional qualifications.

Q5. What is your conclusion on the market-determined cost of equity for NorthWestern's SD operations based upon the results from the sample of regulated companies you selected?

A5. The best point estimate of the cost of equity for NorthWestern's SD gas distribution operations is 11¼ percent for a capital structure with 51.5 percent equity. However, it is more correct to say that the sample results indicate a range of 10¾ to 11¾ percent for the estimated cost of equity. This point estimate is about ½ percent lower than the risk-positioning results for the sub-sample and almost 1 percent higher than the multistage DCF estimate for the sub-sample.

Note, I specify a plus or minus ½ percent range for the return on equity and specify the point estimate to the nearest ¼ percent because I do not believe that it is possible to estimate the cost of equity more precisely than that.

Q6. How is your testimony organized?

A6. The *Sections II and III* of the testimony cover the theory underlying the cost of equity estimation models. Those familiar with cost of capital theory can skip directly to *Section*

IV, which discusses the implementation of the models in this proceeding. *Section V* provides the conclusions.

Specifically, *Section II* formally defines the cost of capital and touches on the principles relating to the cost of capital and capital structure for a business. *Section III* presents the methods used to estimate the cost of capital for the benchmark samples and their associated numerical analyses, and explains the basis of my conclusions for the benchmark sample's returns on equity and overall cost of capital. *Section IV* presents the results of these methods applied to the benchmark sample group, and presents the cost of equity implied by the results. *Appendix B* discusses sample selection and the determination of the market-value capital structures as well as the costs of debt and preferred stock. My conclusions on the cost of equity for the equity financed portion of NorthWestern's South Dakota gas utility assets are presented in *Section V*.

Q7. Please summarize how you approached this task.

A7. I selected a sample of nine regulated natural gas LDCs with business risk comparable to that of NorthWestern's SD gas LDC operations. My analyses consider cost of capital evidence from the risk positioning and discounted cash flow models, but I rely primarily on the results from the risk positioning model because I do not believe that the DCF method is completely reliable at this time for this industry.

Specifically, I estimate the cost of equity for each sample company using both cost-of-equity estimation methods. For each estimate, I combine this value with the sample company's market costs of debt and preferred stock to estimate each firm's overall cost of capital, i.e. its after-tax weighted-average cost of capital ("ATWACC"), using each company's market value capital structure as the weights. For each method of estimating the return on equity, I then report a sample average ATWACC and the estimated cost of equity at a capital structure with same percentage of equity as filed by NorthWestern for its SD operations. I thus present the cost of equity that is consistent with each sample's market information on the cost of capital and the regulatory capital structure of NorthWestern's SD operations. (By "regulatory capital structure," I mean the capital structure that NorthWestern utilizes in its applications.[1])

This method automatically avoids problems that can arise when an analyst focuses separately on the individual components of the overall cost of capital (i.e., the cost of equity and the appropriate capital structure). The danger with that approach is that the estimated cost of equity from the sample may correspond to a very different level of financial risk than would exist at the regulated company's capital structure. The result could be an inconsistency between the allowed return on equity and the financial risk inherent in the regulatory capital structure.

Q8. Why do you believe that the DCF model is less reliable for this industry at this time than the risk positioning model?

A8. Results for the DCF model depend critically on the estimate of the dividend growth rate. A one percent error in the estimate of the growth rate results in a greater than one percent error in the cost of equity estimates. In the recent past, the gas LDC industry could have been characterized as being relatively stable, but that is much less true today. There have been a number of mergers and acquisitions that has resulted in a consolidation within the industry. There are now fewer "pure play" gas LDC companies available to include in a sample. Gas prices have increased dramatically and have been much more volatile lately. Although most of the companies in the gas LDC sample have fuel cost adjustment clauses, the increased volatility of gas prices has increased the uncertainty of the industry's earnings going forward. This uncertainty in earnings is also reflected in the accounting restatements by companies in the industry due to efforts to report accurately the value of inventories. Currently, average forecast growth rates for the sample are lower than they were just a few months ago, but *Value Line's* forecast betas have changed

[1] In the analyses I use the capital structure that is based upon the long-term sources of capital, i.e., long-term debt, preferred equity and common equity. I do not use short-term debt because long-term assets are not generally financed with short-term debt.

very little. Because of these concerns, I report results for a sub-sample which consists of sample companies which have no significant data issues. Estimates from this group are likely to be the most reliable.

Q9. What are the results for the DCF model?

A9. As reported below, the DCF model results display a greater spread and are more variable and therefore less reliable than those based upon the risk positioning model. For example, the simple DCF model results range from a low of 6.5 percent to a high of 10.1 percent before any consideration of differences in financial risk. Results for the more reliable multistage model are less variable, and range from 7.4 to 9.8 percent. (See Table No. MJV-6, Panel A for the simple DCF and Panel B for the multistage DCF) After adjusting for financial risk, the sample average for the multistage DCF model is 9.7 percent for the full sample and 10.3 percent for the more reliable subsample. The corresponding DCF results for the less reliable simple DCF model are 9.1 percent for the full sample and 9.4 for the sub-sample. (Table No. MJV-8, Panels A and B)

Although I do not believe that the DCF results are completely reliable for the reasons stated above, I provide results using the DCF method because it is a method that has been used extensively in the past. In addition, the results from the DCF model serve as a check on the results from the equity risk positioning approach.

Q10. What were the results for the risk positioning model?

A10. The sample average risk positioning results adjusted for differences in financial risk range from a low of 11.1 percent to a high of 11.4 percent for the full sample and 11.5 to 11.8 percent for the more reliable sub-sample when using the long-term risk free rate. (See Table No. MJV-12, Panel A for the full sample and Panel B for the sub-sample.) I also report results for the risk positioning model based upon the short-term risk-free rate, but I do not rely on those estimates in this proceeding.

Q11. You mentioned the importance of considering financial risk when evaluating the results of the models. Please explain how you adjust for financial risk.

A11. Both the DCF and the risk positioning models rely on market data to estimate the cost of equity for the sample companies. That cost of equity estimate captures both the business risk and the financial risk of the assets. Business risk is the risk that the company would have if it were financed entirely with equity. Financial risk is the additional risk carried by the equity holders when debt is used to finance some of the assets. The more debt that is used by a company, the riskier the company's equity becomes. As explained in more detail below, the procedures I use consider both the business risk and the financial risk of the sample companies in comparison to NorthWestern's SD gas operations in determining my recommended cost of equity.

II. COST OF CAPITAL THEORY

A. THE COST OF CAPITAL AND RISK

Q12. Please formally define the "Cost of Capital."

A12. The cost of capital can be defined as *the expected rate of return in capital markets on alternative investments of equivalent risk*. In other words, it is the rate of return investors require based on the risk-return alternatives available in competitive capital markets. The cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. "Expected" is used in the statistical sense: the mean of the distribution of possible outcomes. The terms "expect" and "expected" in this testimony, as in the definition of the cost of capital itself, refer to the probability-weighted average over all possible outcomes.

The definition of the cost of capital recognizes a tradeoff between risk and return that is known as the "security market risk-return line," or "security market line" for short. This line is depicted in Figure 1. The higher the risk, the higher is the cost of capital. A version of Figure 1 applies for all investments. However, for different types of securities, the location of the line may depend on corporate and personal tax rates.

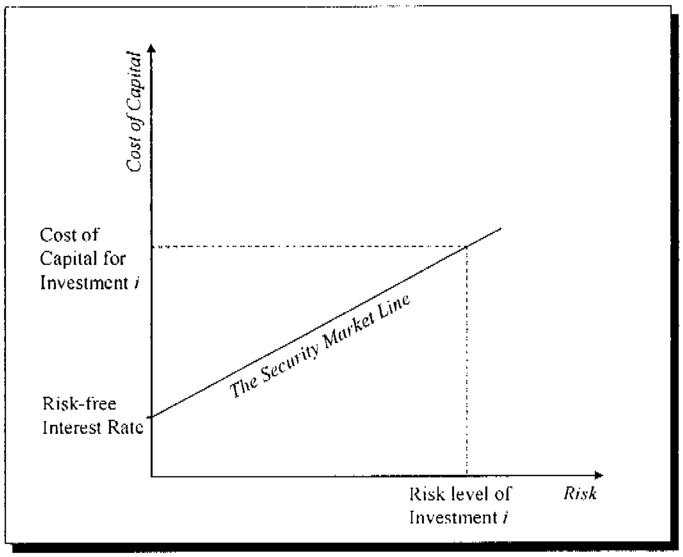

Figure 1: The Security Market Line

Q13. Why is the cost of capital relevant in rate regulation?

A13. It has become routine in U.S. rate regulation to accept the "cost of capital" as the right expected rate of return on utility investment.[2] That practice is normally viewed as consistent with the U.S. Supreme Court's opinions in *Bluefield Waterworks & Improvement Co. v. Public Service Commission*, 262 U.S. 678 (1923), and *Federal Power Commission v. Hope Natural Gas*, 320 U.S. 591 (1944).

From an economic perspective, rate levels that give investors a fair opportunity to earn the cost of capital are the lowest levels that compensate investors for the risks they bear. Over the long run, an expected return above the cost of capital makes customers overpay for service. Regulatory commissions normally try to prevent such outcomes, unless there are offsetting benefits (e.g., from incentive regulation that reduces future cost). At the

[2] A formal link between the cost of capital as defined by financial economics and the right expected rate of return for utilities is established by Stewart C. Myers, "Application of Finance Theory to Public Utility Rate Cases," *The Bell Journal of Economics and Management Science*, 3:58-97 (Spring 1972).

same time, an expected return below the cost of capital shortchanges investors. In the long run, such a return denies the company the ability to attract capital, to maintain its financial integrity, and to expect a return commensurate with that of other enterprises attended by corresponding risks and uncertainties.

More important for customers, however, are the economic issues an inadequate return raises for them. In the short run, deviations of the expected rate of return on the rate base from the cost of capital create a "zero-sum game"-- investors gain if customers are overcharged, and customers gain if investors are shortchanged. In the long run, however, inadequate returns are likely to cost customers -- and society generally -- far more than is gained in the short run. Inadequate returns lead to inadequate investment, whether for maintenance or for new plant and equipment. The costs of an undercapitalized industry can be far greater than the short-run gains from shortfalls in the cost of capital. Moreover, in capital-intensive industries (such as the electric utility or the gas distribution industries), systems that take a long time to decay cannot be fixed overnight. Thus, it is in the customers' interest not only to make sure the return investors expect does not exceed the cost of capital, but also to make sure that it does not fall short of the cost of capital, either.

Of course, the cost of capital cannot be estimated with perfect certainty, and other aspects of the way the revenue requirement is set may mean investors expect to earn more or less than the cost of capital even if the allowed rate of return equals the cost of capital exactly. However, a Commission that sets rates so investors expect to earn the cost of capital on average treats both customers and investors fairly, and acts in the long-run interests of both groups.

B. BUSINESS RISK & FINANCIAL RISK: CAPITAL STRUCTURE AND THE COST OF EQUITY

Q14. Please explain briefly the difference between business risk and financial risk.

A14. Business risk is the risk of a company from its line of business if it used no debt financing. When a firm uses debt to finance its assets, the business risk of the assets is shared between the debt holders and the equity holders, but the equity holders bear more of the risk because debt holders have a prior claim on the company's cash flows. Equity holders are residual claimants, which simply means that equity holders get paid last. Therefore, the goal of selecting a sample is to choose companies whose business risk is comparable to the regulated company in the proceeding.

Q15. Please explain why it is necessary to report the cost of equity adjusted for capital structure.

A15. Briefly, rate regulation in North America tends to focus on the components of the overall cost of capital, and in particular, on what the "right" cost of equity and capital structure should be. Frequently, there is no consideration of whether the financial risks of the sample companies differ among themselves or differ from the regulated company. The cost of equity estimated using the standard models reflects both the business and financial risk of the sample companies. However, the overall cost of capital depends primarily on the business the firm is in, while the costs of the debt and equity components depend not only on the business risk but also on the distribution of revenues between debt and equity. The overall cost of capital is thus the more basic concept.

C. IMPLICATIONS FOR ANALYSIS

Q16. Please explain the implications of the relationship between capital structure and the cost of equity on your testimony.

A16. The risk equity holders carry, and therefore the cost of equity, depends on the capital structure. As leverage increases, financial risk increases, and hence the required return on equity increases. An approach that estimates the cost of equity for each of the sample firms without explicit consideration of the market value capital structure (i.e., the financial risk) underlying those costs risks material errors. The costs of equity of the sample companies at their actual market-value capital structures do not necessarily correspond to the financial risk faced by equity holders in the regulated company, and thus could lead to an unfair rate of return. I avoid this problem by calculating each sample company's ATWACC using its market value capital structure. Using the sample's average overall cost of capital as an estimate for the cost of capital of NorthWestern's SD operations, I then determine the corresponding return on equity at NorthWestern's filed regulatory capital structure. This procedure ensures that the capital structure and estimated cost of equity are consistent for the regulated company.

Q17. To assess the magnitude of financial risk for a rate regulated company, should you use the market-value or the book-value capital structure?

A17. The academic literature supports the view that the market-value capital structure is the relevant quantity for analyzing the cost of equity evidence, which is based on market information.

Q18. Is the use of market values to calculate the impact of capital structure on the risk of equity incompatible with use of a book-value rate base for a regulated company?

A18. No, no more than it is incompatible to use market-based cost of equity estimation methods (such as DCF or the risk positioning model) with a book value rate base. That is, the cost of capital is the fair rate of return on regulatory assets for both investors and customers. Most regulatory jurisdictions in North America measure the rate base using the net book value of assets, not current replacement value or historical cost trended for inflation, but the jurisdictions still apply market-derived measures of the cost of equity to that net book value rate base.

The issue here is "what level of risk is reflected in that cost of equity estimate?" The equity risk level depends on the sample company's market-value capital structure, not its book-value capital structure. *That risk level would be different if the sample company's* *market-value capital structure exactly equaled its book-value capital structure, so the estimated cost of equity would be different, too.*

Q19. Please sum up the implications of this section.

A19. The market risk and, therefore, the cost of equity depend directly on the market-value capital structure of the company or asset in question. It therefore is impossible to compare validly the measured costs of equity of different companies without taking capital structure into account. Capital structure and the cost of equity are inextricably linked, and any effort to treat the two as separate and distinct questions violates basic financial principles.

Q20. How should a cost of capital analyst implement this principle?

A20. Analysts should treat the market-value weighted average of the cost of equity and the after-tax current cost of debt, or the "ATWACC" for short,[3] as constant for a particular line of business for companies not in financial distress or with unusual capital structures. Sample evidence should be analyzed to determine the sample's average ATWACC, which can be compared across different firms or industries. The economically appropriate cost of equity for a regulated firm is the quantity that, when applied to the *regulatory* capital structure, produces the same ATWACC. That value is the cost of equity that the sample would have, estimation problems aside, if the sample's market-value capital structure had been equal to the regulatory capital structure in question.

[3] This quantity typically is called the "weighted-average cost of capital" or "WACC" in finance textbooks. The textbook WACC equals the *market*-value weighted average of the cost of equity and the *after-tax*, *current* cost of debt. However, rate regulation in North America has a legacy of working with another weighted-average cost of capital, the *book*-value weighted average of the cost of equity and the *before-tax*, *embedded* cost of debt. Accordingly, in regulatory settings it's useful to refer to the textbook WACC as the "ATWACC," or "after-tax weighted-average cost of capital." I follow that practice here.

Q21. Can you provide a simple example of the calculation of the cost of equity consistent with the market-determined estimate of the sample's average overall cost of capital?

A21. Yes. Consider the following equation to calculate the ATWACC:[4]

$$ATWACC = r_D \times D \times (1 - T_C) + r_E \times E \qquad (1)$$

where r_D = market cost of debt,
r_E = market cost of equity,
T_C = corporate income tax rate,
D = percentage of debt in the capital structure, and
E = percentage of equity in capital structure.

The cost of equity consistent with overall cost of capital estimate (ATWACC), the market cost of debt and equity, the marginal corporate income tax rate and the amount of debt and equity in the capital structure can be determined by solving equation (1) for r_E.

III. COST OF CAPITAL METHODOLOGY

Q22. How is this section of your testimony organized?

A22. As noted in Section II, I estimate the cost of capital using a sample of comparable risk companies. This section first outlines the steps involved in selecting a benchmark sample, in determining the market-value capital structure, and in estimating the sample companies' costs of debt. It then turns to the procedures for estimating the costs of equity and describes the two cost of equity estimation methodologies used in this testimony, the DCF method and the risk positioning approach. These are the foundations of my cost of capital calculations, which I present in the following section and which I use to derive my recommended cost of equity for NorthWestern's SD regulated gas assets at their regulatory capital structure.

[4] Note that this equation assumes that only debt and equity are in the capital structure, but it is simple to add preferred equity to the equation.

A. SAMPLE SELECTION CRITERIA

Q23. What is the goal of your sample selection procedures?

A23. The overall cost of capital for a part of a company depends on the risk of the business in which the part is engaged, not on the overall risk of the parent company on a consolidated basis. According to financial theory, the overall risk of a diversified company equals the market-value-weighted average of the risks of its components.

Estimating the cost of equity for NorthWestern's SD regulated gas distribution assets is the subject of this proceeding. The ideal comparative sample for NorthWestern's SD operations would be a number of companies that are publicly traded "pure plays" in the natural gas distribution business. "Pure play" is an investment term referring to companies with operations only in one line of business. Publicly traded firms, firms whose shares are freely traded on stock exchanges, are ideal because the best way to infer the cost of capital is to examine evidence from capital markets on companies in the given line of business.

In addition to providing a sample of comparable business risk, a good sample should provide reliable cost of capital estimates. For this reason, I apply a set of criteria that are intended to screen out companies that have characteristics which may bias the cost of equity estimates. The details are in Appendix B.

B. CAPITAL STRUCTURE & THE COST OF DEBT

1. Market-Value Capital Structure

Q24. What capital structure information do you require?

A24. For reasons discussed above, explicit evaluation of the market-value capital structures of the sample companies is vital for a correct interpretation of the market evidence on the return on equity. This requires estimates of the market values of common equity, preferred equity and debt, and the current market costs of preferred equity and debt.

Q25. Please describe how you calculate the market values of common equity, preferred equity and debt.

A25. I estimate the market value capital structure for each sample company by estimating the market values of common equity, preferred equity and debt from the most recent publicly available data. The details are in Appendix B.

Briefly, the market value of common equity is the price per share times the number of shares outstanding. For the risk positioning approach, I use the last five trading days of each year to calculate the market value of equity for the year. I then calculate the average capital structure over the corresponding five-year period used to estimate the "beta" risk measures for the sample companies.[5] This procedure matches the estimated beta to the degree of financial risk present during its estimation period. In the DCF analyses, I use the average stock price over the 15 trading days ending on the day that the earnings growth rate forecasts are obtained from Bloomberg.[6]

The market value of debt is estimated at its book value adjusted by the difference between the "Estimated Fair (market) Value" and the "carrying cost" of long-term debt reported in each company's 10-K.[7] The market value of preferred stock for the samples is set equal to its book value because the market values and book values do not differ much and because the percent of preferred stock in the capital structures of the sample companies is relatively small compared to the debt and common equity components.

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[5] *Value Line* uses five years of historical data to estimate its forecasted betas.

[6] Forecasts were obtained on April 9, 2007 for all companies in the benchmark gas LDC sample.

[7] The book value of debt from Bloomberg includes all interest-bearing financial obligations that are not current and includes capitalized leases and mandatory redeemable preferred and trust preferred securities in accordance with FASB 150 effective June 2003. See Bloomberg definition of long-term debt for additional detail.

2. Market Costs of Debt and Preferred Equity

Q26. How do you estimate the current market cost of debt?

A26. The market cost of debt for each company in the DCF analysis is the current yield reported by Bloomberg for its index of public utility company bonds corresponding to the sample company's current debt rating as classified by S&P. The risk positioning analysis, on the other hand, uses the current yield of a utility bond that corresponds to the five-year average debt rating of each company so as to match consistently the horizon of information used by *Value Line* to estimate company betas.

Q27. How do you estimate the market cost of preferred equity?

A27. For each company with preferred stock, the cost of preferred equity for each company is set equal to the yield on an index of preferred stock as reported in the Mergent Bond Record corresponding to the S&P rating of that company's debt.

3. Risk-Free Interest Rate Forecast

Q28. How do you obtain the forecasts of the risk-free interest rates over the period the utility rates set here are to be in effect?

A28. I obtain these forecast rates using data provided by Bloomberg. In particular, I use the reported government debt yields from the "constant maturity series". This information is displayed in Panels A and B of Table No. MJV-9.

Q29. What values do you use for the short-term and long-term risk-free interest rates?

A29. I use a value of 3.8 percent for the short-term risk-free interest rate and a value of 4.9 percent for the long-term risk-free interest rate as the benchmark interest rates in the equity risk premium analyses. These forecasts are constructed by using historical yield curve data to find the long-run average implied term premia on government securities, and combining these with recent yield curve data. Details of their calculation can be found in the Workpapers to Table No. MJV-9.

C. COST OF EQUITY METHODS

Q30. How do you estimate the cost of equity for your sample companies?

A30. Recall the definition of the cost of capital from the outset of my testimony: *the expected rate of return in capital markets on alternative investments of equivalent risk.* My cost of capital estimation procedures address three key points implied by the definition:

1. Since the cost of capital is an expected rate of return, it cannot be directly observed; it must be inferred from available evidence.

2. Since the cost of capital is determined in capital markets (e.g., the New York Stock Exchange), data from capital markets provide the best evidence from which to infer it.

3. Since the cost of capital depends on the return offered by alternative investments of equivalent risk, measures of the risks that matter in capital markets are part of the evidence that needs to be examined.

Q31. How does the above definition help in cost of capital estimation?

A31. The definition of the cost of capital recognizes a tradeoff between risk and expected return - the security market line - plotted earlier in Figure 1. Cost of capital estimation methods take one of two approaches: (1) they try to identify a comparable-risk sample of companies and to estimate the cost of capital directly; or (2) they establish the location of the security market line and estimate the relative risk of the security, which jointly determine the cost of capital. In terms of Figure 1, the first approach focuses directly on the vertical axis, while the second focuses both on the security's position on the horizontal axis and on the position of the security market line.

The first type of approach is more direct, but ignores the wealth of information available on securities not thought to be of precisely comparable risk. The "discounted cash flow" or "DCF" model is an example. The second type of approach, sometimes known as "equity risk premium approach," requires an extra step, but as a result can make use of information on all securities, not just a very limited subset. The Capital Asset Pricing Model ("CAPM") is an example. While both approaches can work equally well if conditions are right, one may be preferable to the other under other circumstances. In particular, approaches that rely on the entire security market line are less sensitive to deviations from the assumptions that underlie the model, all else equal. I examine both DCF and risk positioning approach evidence for the sample.

1. The Risk Positioning Approach

Q32. Please explain the risk positioning method.

A32. The risk positioning method estimates the cost of equity as the sum of a current interest rate and a company specific risk premium. It is therefore sometimes also known as the "risk premium" approach. This approach may sometimes be applied informally. For example, an analyst or Commission may check the spread between interest rates and what is believed to be a reasonable estimate of the cost of capital at one time, and then apply that spread to changed interest rates to get a new estimate of the cost of capital at another time.

More formal applications of the risk positioning approach take full advantage of the security market line depicted in Figure 1 - they use information on all securities to identify the security market line and derive the cost of capital for the individual security based on that security's relative risk. This reliance on the entire security market line makes the method less vulnerable to the kinds of problems that arise for the DCF method, which relies on one stock at a time. The risk positioning approach is widely used and underlies most of the current research published in academic journals on the nature, determinants and magnitude of the cost of capital.

Q33. How are the "more formal" applications of risk positioning approach implemented?

A33. The first step is to specify the current values of the benchmarks that determine the security market line. The second is to determine the security's or investment's relative risk. The third is to specify exactly how the benchmarks combine to produce the security market line, so the company's cost of capital can be calculated based on its relative risk.

All of these elements and how they relate are usefully formulated in the framework of the CAPM.

a) The Capital Asset Pricing Model

Q34. Please start with the CAPM, by describing the model.

A34. As noted above, modern models of capital market equilibrium express the cost of equity as the sum of a risk-free rate and a market risk premium. The CAPM is the longest-standing and most widely used of these theories. The CAPM states that the cost of capital for an investment, *s*, (e.g., a particular common stock) is given by the following equation:

$$k_s = r_f + \beta_s \times MRP \qquad (2)$$

where k_s is the cost of capital for investment *s*; r_f is the risk-free rate, β_s is the beta risk measure for the investment *s*; and *MRP* is the market risk premium.

The CAPM relies on the empirical fact that investors price risky securities to offer a higher expected rate of return than safe securities do. It says that the security market line starts at the risk-free interest rate (that is the return on a zero-risk security, the y-axis intercept in Figure 1, equals the risk-free interest rate). Further, it says that the risk premium over the risk-free rate equals the product of beta and the risk premium on a value-weighted portfolio of all investments, which by definition has average risk.

b) The Empirical Capital Asset Pricing Model

Q35. What other equity risk premium model do you use?

A35. Empirical research has long shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premia than predicted by the CAPM and high-beta stocks tend to have lower risk premia than predicted. A number of variations on the original CAPM theory have been proposed to explain this finding, but this finding can also be used to estimate the cost of capital directly, using beta to measure relative risk without simultaneously relying on the CAPM.

The second model makes use of these empirical findings. It estimates the cost of capital with the equation, where α is the "alpha" adjustment of the risk-return line, a constant,

$$k_s = r_f + \alpha + \beta_s \times (MRP - \alpha) \qquad (3)$$

and the other symbols are defined as above. I label this model the Empirical Capital Asset Pricing Model, or "ECAPM." The alpha adjustment has the effect of increasing the intercept but reducing the slope of the security market line in Figure 1 which results in a security market line that more closely matches the results of empirical tests.

Q36. Why is it appropriate for you to use the empirical CAPM?

A36. The CAPM has not generally performed well as an empirical model, but its short-comings are directly addressed by the ECAPM. Specifically, the ECAPM recognizes the consistent empirical observation that the CAPM underestimates (overestimates) the cost of capital for low (high) beta stocks. In other words, the ECAPM is based on recognizing that the actual slope of the risk-return tradeoff is flatter than predicted and the intercept higher based upon repeated empirical tests of the CAPM. The alpha parameter (α) in the ECAPM adjusts for this fact. The difference between the CAPM and the type of relationship identified in the empirical studies is depicted in Figure 2.

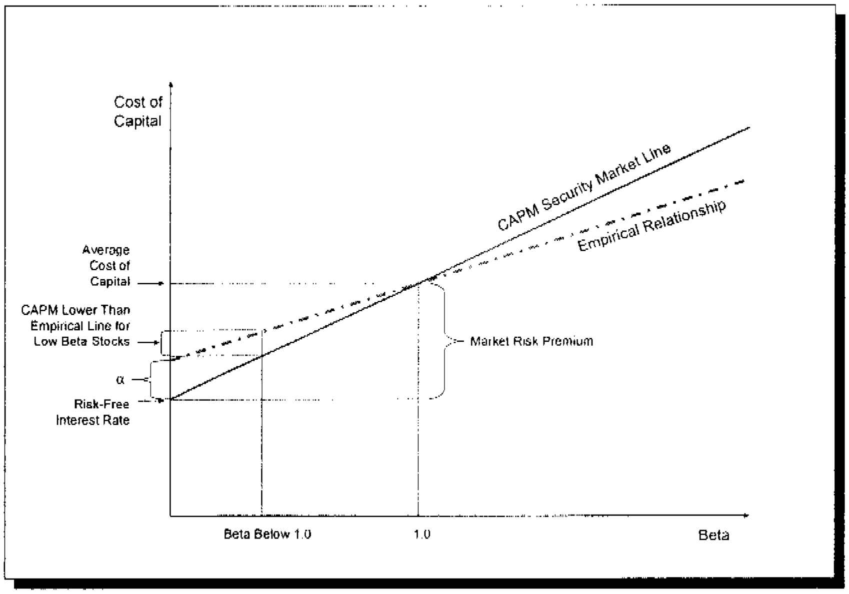

Figure 2: The Empirical Security Market Line

Research supports values for α of one to seven percent when using a short-term interest rate. I use baseline values of α of two percent for the short-term risk-free rate and 0.5 percent for the long-term risk-free rate. I also conduct sensitivity tests for different values of α. For the short-term risk-free rate I use values for α of one, two and three percent. For the long-term risk-free rate, the corresponding α values are zero, 0.5 and 1.5 percent. These values are lower than would be justified by the magnitude of the misestimation in the tests of the CAPM. I use lower values of α when using the long-term risk-free rate because use of a long-term risk-free rate incorporates some of the desired effect of using the ECAPM. That is, the long-term risk-free rate version of the security market line has a higher intercept and a flatter slope than the short-term risk-free version which is the version that has been extensively tested. Thus, it is likely that I do not need to make the same degree of adjustment when I use the long-term risk-free rate.

2. Discounted Cash Flow Method

Q37. Please describe the discounted cash flow approach.

A37. The DCF model takes the first approach to cost of capital estimation, i.e., to attempt to estimate the cost of capital in one step. The method assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The method also assumes that this present value can be calculated by the standard formula for the present value of a cash flow stream:

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \cdots + \frac{D_T}{(1+k)^T} \tag{4}$$

where "P" is the market price of the stock; "D_i" is the dividend cash flow expected at the end of period i; "k" is the cost of capital; and "T" is the last period in which a dividend cash flow is to be received. The formula just says that the stock price is equal to the sum of the expected future dividends, each discounted for the time and risk between now and the time the dividend is expected to be received.

Most DCF applications go even further, and make very strong (i.e., unrealistic) assumptions that yield a simplification of the standard formula, which then can be rearranged to estimate the cost of capital. Specifically, if investors expect a dividend stream that will grow *forever* at a steady rate, the market price of the stock will be given by a very simple formula,

$$P = \frac{D_1}{(k-g)} \tag{5}$$

where "D_1" is the dividend expected at the end of the first period, "g" is the perpetual growth rate, and "P" and "k" are the market price and the cost of capital, as before. Equation (5) is a simplified version of equation (4) that can be solved to yield the well known "DCF formula" for the cost of capital:

$$k = \frac{D_1}{P} + g = \frac{D_0 \times (1+g)}{P} + g \tag{6}$$

where "D_0" is the current dividend, which investors expect to increase at rate g by the end of the next period, and the other symbols are defined as before. Equation (6) says that if equation (5) holds, the cost of capital equals the expected dividend yield plus the (perpetual) expected future growth rate of dividends. I refer to this as the simple DCF model. Of course, the "simple" model is simple because it relies on very strong (i.e., very unrealistic) assumptions.

Q38. Are there other versions of the DCF models besides the "simple" one?

A38. Yes. The constant growth rate DCF model requires that dividends and earnings grow at the same rate for companies that earn their cost of capital on average.[8] It is inconsistent with the theory on which the model is based to have different growth rates in earnings and dividends over the period when growth is assumed to be constant. If the growth in dividends and earnings were expected to vary over some number of years before settling down into a constant growth period, then it would be appropriate to estimate a multistage DCF model. In the multistage model, earnings and dividends can grow at different rates, but must grow at the same rate in the final, constant growth rate period. A difference between forecasted dividend and earnings rates therefore is a signal that the facts do not fit the assumptions of the simple DCF model.

So, I consider a variant of the DCF model that relies on slightly less strong assumptions in that it allows for varying dividend growth rates in the near term before assuming a

[8] Why must the two growth rates be equal in a steady-growth DCF model? Think of earnings as divided between reinvestment, which funds future growth, and dividends. If dividends grow faster than earnings, there is less investment and slower growth each year. Sooner or later dividends will equal earnings. At that point, growth is zero because nothing is being reinvested (dividends are constant). If dividends grow slower than earnings, each year a bigger fraction of earnings are reinvested. That makes for ever faster growth. Both scenarios contradict the steady-growth assumption. So if you observe a company with different expectations for dividend and earnings growth, you know the company's stock price and its dividend growth forecast are inconsistent with the assumptions of the steady-growth DCF model.

perpetual growth rate beginning in year eleven. I use the forecast growth of GDP as the forecast of the long-term growth rate, i.e. year eleven on. This is a variant of the "multistage" DCF method.

Q39. What are the merits of the DCF approach?

A39. The DCF approach is conceptually sound if its assumptions are met, but can run into difficulty in practice because those assumptions are so strong, and hence so unlikely to correspond to reality. Two conditions are well known to be necessary for the DCF approach to yield a reliable estimate of the cost of capital: the variant of the present value formula that is used must actually match the variations in investor expectations for the growth of dividends, and the growth rate(s) used in that formula must match current investor expectations. Less frequently noted conditions may also create problems.

Q40. Do you agree that estimating the "right" dividend growth rate is the most difficult part for the implementation of the DCF approach?

A40. Yes. Finding the right growth rate(s) is the usual "hard part" of a DCF application. The original approach to estimation of *g* relied on average historical growth rates in observable variables, such as dividends or earnings, or on the "sustainable growth" approach, which estimates *g* as the average book rate of return times the fraction of earnings retained within the firm. But it is highly unlikely that these historical averages over periods with widely varying rates of inflation and costs of capital will equal current growth rate expectations. Although there has been relatively less turmoil in the natural gas LDC line of business, there have been a number of mergers and acquisitions in the industry. In addition, the price of natural gas has increased dramatically and has been much more volatile lately. Although most of the sample companies have fuel cost adjustment clauses, the increased volatility of gas prices has increased the uncertainty of the industry's earnings going forward. This uncertainty is also reflected in the accounting restatements in recent years as well as more involvement in non-regulated or non-gas activities. Therefore, because the underlying forecasts of earnings growth rates are less reliable, the DCF estimates for the gas LDC sample are less reliable than they have been in the recent past.

IV. COST OF CAPITAL ESTIMATES

A. COMPANY BACKGROUND

Q41. Please describe Northwestern's South Dakota gas distribution assets?

A41. Northwestern serves approximately 83,900 customers in 59 communities in South Dakota with approximately 2,200 miles of distribution gas mains. Purchase adjustment clauses contained in South Dakota and Nebraska tariffs allow the Company to reflect increases or decreases in gas supply and interstate transportation costs on a timely basis, so the Company is generally allowed to pass natural gas prices through to customers. The Company does not have a weather adjustment clause in South Dakota.

B. SAMPLE SELECTION

Q42. How did you select your sample of natural gas LDCs?

A42. The goal was to create a sample of companies whose primary business is as a regulated natural gas LDC with business risk generally similar to that of NorthWestern's SD gas distribution operations. I considered the universe of 23 companies classified by the *Value Line Investment Survey Plus* as natural gas LDCs, and added Vectren Corporation to my sample because it is often viewed as a natural gas LDC. Vectren is involved in both gas and electric distribution activities, but now obtains a substantially amount of income from its gas distribution operations.[9] This company is also covered by *Value Line*, but is classified as an Electric Utility due to its regulated electric operations.

[9] Vectren Utility Holdings, Inc.'s 2006 10K reveals that about 45.4 percent of its income is from regulated gas distribution activities and 45.5 percent from regulated electric operations. Because it has a substantial amount of regulated electric activity, I exclude it from the sub-sample of companies I consider to be the most

Companies were first eliminated if their operating regions were outside of the continental USA. I then applied my standard selection criteria to narrow the sample to those companies likely to have reliable cost of equity estimates. This resulted in a benchmark sample of nine companies which are outlined in Table 1. NorthWestern Corporation has been added to Table 1 for comparison purposes. Additional details on the sample selection process can be found in Appendix B.

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representative of the natural gas distribution line of business and to be most free of characteristics that may bias cost of equity estimates (see below).

Table 1: Summary of the Sample's Characteristics

Company	Business Activities [1]	Revenue (2006) ($MM) [2]	Regulated Gas Assets [3]	Total Regulated Assets [4]	Market Cap. (2006) ($MM) [5]	S&P Bond Rating (2007) [6]	Beta [7]	Long-Term Growth Estimate [8]
Atmos Energy Corp	D P ST M	6,152	95.5%	95.5%	2,622	BBB	0.80	5.8%
The Laclede Group	D M OTH	1,998	89.5%	89.5%	753	A	0.85	3.0%
Northwest Natural Gas Co	D ST OTH	1,013	98.0%	98.0%	1,161	AA-	0.75	4.8%
Piedmont Natural Gas Co	D P M ST	1,925	97.2%	97.2%	2,022	A	0.80	5.0%
South Jersey Industries Inc	D P ST M EM OTH	931	78.1%	78.1%	981	BBB	0.70	6.3%
Southwest Gas Corp	D PCon	2,025	96.2%	96.2%	1,613	BBB-	0.85	5.5%
WGL Holdings Inc	D ST M EM OTH	2,638	99.8%	99.8%	1,603	AA-	0.85	3.7%
AGL Resources Inc	D M WH EInv	2,621	74.3%	74.3%	3,042	A-	0.95	4.5%
Vectren Corp	D IE EM	2,042	56.8%	93.9%	2,156	A-	0.95	2.2%
NorthWestern Corp†	**D P ST IE ET ED**	**1,133**	**31.8%**	**96.4%**	**1,276**	**BB+**	**na**	**na**

Notes and Sources:

† Statistics specific to NorthWestern Corp's South Dakota regulated gas operations are unavailable.

[1] D – Distribution P – Pipeline M – Natural Gas Marketing ST – Natural Gas Storage ET - Electric Transmission ED - Electric Distribution IE – Integrated Electric EM – Electric Marketing EInv – Energy Investments PCon -- Pipeline Construction WH – Wholesale Activities OTH – Other (small component).
Sources: Company 10-K's for 2006 fiscal year.

[2] See Table MJV-2.

[3] Estimated share of total assets based on company 10-K

[4] Estimated share of total assets based on company 10-K

[5] See Table MJV-3 for calculation.

[6] See Workpaper #1 to Table MJV-11

[7] Value Line Investment Survey – see Workpaper # 1 to Table MJV-10

[8] See Table MJV-5.

1. The Gas LDC Sub-Sample

Q43. Why do you advocate summarizing the cost of capital estimates from a sub-sample of the gas LDC companies as well as for the full sample?

A43. Although the sample selection criteria are designed to screen out any company that has characteristics that may bias the cost of equity estimates, some of the sample companies are better than others. For example, although still investment grade, Southwest Gas is at the bottom of the scale of investment grade credit ratings and has a relatively low average equity thickness over the past five years – 40.1 percent compared to 61.8 percent for the remaining companies. Closer investigation shows that Southwest Gas's capital structure has been shifting rapidly toward equity over the last five years, with a level of about 50 percent over the most recent two years. This kind of instability suggests a potential reliability problem for estimates of this company's cost of capital. The Laclede Group's market cap of $688 million is a bit smaller than the average of the group, but with revenues of more than $1.5 billion, it is still a large company. In 2006, Piedmont Natural Gas restated some portions of its 2003-2005 financial reports. Although this can generally lead to less reliable estimates from the equity estimation models, the restatements were not caused by fraudulent activities but were due to an accounting error in the classification of hedging amounts. This type of reclassification would not be expected to change the value of the firm and prices did not show any erratic behavior in the period surrounding the announcement of this reclassification. A potential concern for the DCF estimates is that the industry has experienced a sustained level of merger and acquisition activity over the last five years that has implication for the stability of the industry necessary for the reliable application of the DCF model. Due to the concerns with the sample, I also report the results for a sub-sample of the gas LDC sample that consists of companies with no material data issues.

2. Relative Risk of the Sample and NorthWestern's SD Gas Utility

Q44. Could you please summarize the general characteristics of the companies in the sample and those of NorthWestern's SD operations?

A44. Yes. The sample consists of nine gas LDCs with generally similar risk characteristics to those of NorthWestern's SD operations. Like NorthWestern's SD operations, they all have fuel-cost adjustment clauses which either remove or significantly reduce their exposure to this risk. In their 10-Ks, all sample companies report that they engage in hedging activities to further reduce this risk. In addition, seven of the nine companies have weather adjustment clauses which NorthWestern does not have for its SD gas operations. NorthWestern is currently rated BB+ by S&P, and its S&P Business Profile is 5.[10]

[10] NorthWestern's SD gas operation does not have a separate S&P business profile rating.

Table 2: Risk Factors Summary for the Gas LDC Sample

Company Specific Risk Analysis					
Company [1]	**Fuel Cost Adjustment [2]**	**Weather Normalization [3]**	**Fuel Cost Hedging [4]**	**Storage Facilities [5]**	**S&P Business Profile [6]**
Atmos Energy (GA, KS, KY, LA, TX, MS, TN, VA)	Yes	Yes	S & D	Yes	4
Laclede Group (MO)	Yes	NO	D	Yes	3
Northwest Natural Gas (WA, OR)	Yes	Yes	S & D	Yes	1
Piedmont Natural Gas (SC, TN, NC)	Yes	Yes	Yes	Yes	2
South Jersey Industries (NJ)	Yes	Incentive Prog.	D	Yes	na
Southwest Gas (AZ, NV, CA)	Yes	Yes	Fix & Var Price	Yes	3
WGL Holdings (DC, VA, MD)	Yes	Yes	D	No	3
AGL Resources (GA, FL, MD, NJ, TN, VA)	Yes	Yes	D	Yes	4
Vectren (IN, OH)	Yes	Yes	D	Yes	3
NorthWestern Corp† (MT, SD, NE)	**Yes**	**No**	**Fix & Var Price**	**Yes**	**5**

Notes and Sources: *All company 10-K sources are for the 2006 fiscal year.*

† Statistics specific to NorthWestern Corp's South Dakota regulated gas operations are unavailable.

[1] States of operation as reported in company 10-Ks for significant operations.

[2] Yes indicates a mechanism was reported in company 10-Ks, but different mechanisms exist by company and by state. If a mechanism exists, it generally allows for 100% recovery of prudent costs.

[3] Yes indicates a mechanism was reported in company 10-Ks, but different mechanisms exist by company and by state. South Jersey Industries reports participation in a Conservation incentive program.

[4] S - Storage D - Financial Derivatives Fix & Var Price - Price formulas are used to help mitigate weather risks. As reported in company 10-K's

[5] Information from company 10-Ks.

[6] S&P Business Profile as published on April 28, 2006 in S&P's *U.S. Utility and Power Ranking List*

Q45. How does the risk of the sample compare to the risk of NorthWestern's SD gas distribution operations?

A45. In general, the benchmark sample has comparable business risk to NorthWestern's SD gas operations. NorthWestern has a higher business risk profile than the sample, but that is for the company as a whole, and its unsecured credit rating is lower than the sample. These factors suggest that it is conservative to view the business risk of the sample as comparable to NorthWestern's SD gas operations.

C. COST OF CAPITAL AND COST OF EQUITY ESTIMATES

Q46. Please summarize the results of the risk positioning and DCF methodologies in estimating the average cost of capital for the benchmark sample and the implications for NorthWestern's SD operations' cost of equity?

A46. Table 3 below summarizes the risk positioning and DCF cost of equity estimates and the resulting sample average ATWACC estimates for the benchmark gas LDC sample, along with the implied cost of equity for NorthWestern's SD operations at a regulatory capital structure with 51.5 percent equity.

Q47. How did you determine a representative tax rate to use in your cost of capital estimation?

A47. South Dakota does not presently levy state corporate incomes taxes so I use the current federal corporate tax rate of 35 percent.

Q48. How were the cost of equity estimates derived from the risk positioning approach for the benchmark sample?

A48. I derive two sets of risk-positioning estimates, one using long-term forecasts of the risk-free rate and market risk premium, and one using short-term forecasts. The long-term

Table 3: Cost of Equity Estimates for NorthWestern's SD Gas Operations

Regulatory Capital Structure: *51.5% Equity / 48.5% Debt* *2007 Tax Rate:* *35%*

	METHODS								
	RISK POSITIONING (using Long-Term Risk-Free Rate)			RISK POSITIONING (using Short-Term Risk-Free Rate)				DCF	
	CAPM	α = 0.5%	α = 1.5%	CAPM	α = 1%	α = 2%	α = 3%	Simple	Multi
[1] Gas LDC Sample*									
Cost of Equity	11.1%	11.2%	11.4%	11.3%	11.5%	11.7%	11.9%	9.1%	9.7%
Average ATWACC	7.7%	7.7%	7.8%	7.7%	7.8%	7.9%	8.0%	6.6%	6.9%
[2] Sub-sample* Average									
Cost of Equity	11.5%	11.6%	11.8%	11.6%	11.9%	12.1%	12.3%	9.4%	10.3%
Average ATWACC	7.8%	7.9%	8.0%	7.9%	8.0%	8.2%	8.3%	6.8%	7.2%

[3] Risk Positioning Security Market Line Parameters:

Short-Term		*Long-Term*		Multi-Stage DCF Parameter:	
Risk Free Rate Estimate:	3.8%	Risk Free Rate Estimate:	4.9%	GDP	
Estimated Market Risk Premium:	8.0%	Estimated Market Risk Prem	6.5%	Growth	5.1%

Sources and Notes:

* For the MJV US Gas LDC Sample , Risk Positioning data from Table No. MJV-12 and DCF data from Table No. MJV-6.

[1] , [2] The Gas LDC sample consists of Atmos Energy Corp, Laclede Group Inc, Northwest Natural Gas Co, Piedmont Natural Gas Co, South Jersey Industries Inc, Southwest Gas Corp, WGL Holdings Inc, AGL Resources Inc, and Vectren Corp. The sub-sample includes only Laclede Group Inc, Northwest Natural Gas Co, Piedmont Natural Gas Co. and WGL Holdings Inc.

[3] See Testimony, Section IV.C for details on Risk Positioning and DCF parameters used in estimates.

risk-free interest rate forecast is 4.9 percent and the corresponding estimated market risk premium is 6.5 percent. For the short-term risk-free rate, the corresponding values are 3.8 percent and 8.0 percent respectively.

The two risk positioning models (CAPM and ECAPM) are estimated for each horizon, with the long-term estimates utilizing two values of the ECAPM parameter (0.5% and 1.5%), and the short-term estimates utilizing three values of the ECAPM parameter (1%, 2%, and 3%). The risk positioning cost of equity estimates for the gas LDC sample are displayed in Table No. MJV-10, Panels A and B. The cost of equity estimates are subsequently combined with each company's estimated cost of debt and preferred equity to calculate the company's ATWACC using each company's market value capital structure. These calculations and the resulting sample average ATWACC for both the full sample and sub-sample are presented in Table No. MJV-11. Panels A-C of Table No. MJV-11 rely on the cost of equity estimates from the long-term version of the model, while Panels D-G utilize the estimates from the short-term version of the model. The sample and sub-sample average ATWACC and corresponding cost of equity estimates at NorthWestern's 51.5 percent equity capital structure for each cost of equity estimation methods are displayed in Table No. MJV-12, Panels A and B. These results are summarized in Table 3 above.

Q49. What are the DCF estimates for the gas LDC sample?

A49. For each sample company, cost-of-equity estimates are calculated for the two versions of the DCF method. The DCF estimates for each company's cost of equity are displayed in Table No. MJV-6, Panel A (simple DCF) and Panel B (multistage DCF). The sample and sub-sample average ATWACCs for each method are calculated in Table No. MJV-7, Panels A and B, and are used in Table No. MJV-8, Panels A and B, to derive the resulting return on equity at NorthWestern's SD operations 51.5 percent equity capital structure. These results are summarized in Table 3 above, along with the sample and sub-sample average ATWACC numbers. Table 3 shows a cost of equity of 9.1 percent when using the simple DCF model but 9.7 percent from the multistage DCF model for the full sample. The corresponding results for the sub-sample are somewhat higher at 9.4 percent for the simple DCF and 10.3 percent for the multistage DCF. As discussed above, the sub-sample is likely to be a more reliable measure of the cost of capital for this industry. The industry has had more mergers and acquisition in recent years, and the companies in the industry have been more heavily involved in non-regulated activities such as gas marketing which has affected their earnings growth estimates. The variation in the estimates from the simple DCF compared to the multistage model, however, likely reflect the unique events in the industry and suggest that the simple DCF estimates are less reliable than the risk positioning estimates at this time.

V. CONCLUSIONS

Q50. What conclusions do you draw from the DCF estimates regarding the cost of equity for NorthWestern's SD gas operations?

A50. A review of Table No. MJV-6, Panel A shows that the simple DCF cost of equity estimates are highly variable and have a range of 3.6 percent, from a low of 6.5 percent for Vectren Corp. to a high of 10.1 percent for Atmos Energy Corp. The multistage estimates are much less variable, but still have a relatively wide range of 2.4 percent, from a low of 7.4 percent for Southwest Gas Corp. to a high of 9.8 percent for The Laclede Group Inc. The multistage DCF model adjusts for the fact that the earnings forecasts available for each company span only a five-year period, and in my view, the multistage DCF model provides more reliable results. Therefore, the most reliable of the DCF results for NorthWestern's SD gas operations is the 10.3 percent estimate for the multistage version of the DCF for the sub-sample. However, in my opinion, the variability of the DCF results demonstrates that the conditions for the completely reliable implementation of the DCF model do not obtain for the sample at this time. I therefore place little weight on the DCF results.

Q51. Do you have any general comments regarding the results of the risk positioning models?

A51. The estimates based upon the short-term risk-free rate are higher on average than the estimates using the long-term risk-free rate, partially because the yield curve is currently flat or slightly inverted, i.e., the yield on short-term Treasury bills exceeds the yield on long-term Treasury bonds. Table No. MJV-9, Panel A shows that 30-day Treasury bills are currently yielding 5.16 percent compared to only 4.90 percent for long-term Treasury bonds. The calculations displayed in Panel B, Workpaper #1 to Table No. MJV-9 show that the yield on long-term Treasury bonds has averaged about 150 basis points more than the yield on 30-day Treasury bills over the last 80 years. The increased yield on short-term Treasury bills reflects the efforts by the Federal Reserve ("Fed") to prevent the rate of inflation from increasing any further. If the Fed believes that inflation is not yet contained, short-term rates are likely to increase further. On the other hand, if inflation is judged to be under control, short-term rates may decline as fears of recession replace those of inflation. Because of this uncertainty, I believe that the estimates using the long-term risk-free rate are more reliable at this time.

Q52. Please describe the results from the long-term version of the risk positioning model.

A52. Of those results, the CAPM values deserve the least weight, because this method does not adjust for the empirical finding that the cost of capital is less sensitive to beta than predicted by the CAPM (which my testimony considers by using the ECAPM). Conversely, the ECAPM numbers deserve the most weight, because this method adjusts for the empirical findings.

For the gas LDC sample, the cost of equity estimates using the long-term risk free rate and adjusted for a capital structure with a 51.5 percent equity ratio range from 11.1 to 11.4 percent for the full sample and from 11.5 to 11.8 for the sub-sample. The short-term estimates are 20 to 50 basis points higher on average than the long-term ones, ranging from 11.3 to 11.9 percent in the full-sample and 11.6 to 12.3 percent for the sub-sample. A review of the results in Panels A and B of Table No. MJV-10 also shows that the estimates are much less variable than for the DCF model. For example, considering the long-term ECAPM (0.5%) results in Panel A, one sees that the range is only 1.5 percent, from a low of 9.6 percent to a high of 11.1 percent with no significant outliers, whereas the range for the DCF model are 6.5 to 10.1 percent (simple DCF) and 7.4 to 9.8 percent (multistage DCF). (See Table No. MJV-6, Panels A and B.)

Q53. Given the results of the two models, what is your conclusion regarding the cost of equity for NorthWestern's SD gas distribution assets?

A53. I believe that NorthWestern's SD operations are of comparable business risk to the sample so the sample average cost of equity estimates adjusted for differences in finance risk represent a good estimate of the cost of equity for NorthWestern's SD operations. I make no adjustment to the cost of equity estimates for business risk differences between the sample and NorthWestern. Focusing on the middle values in Table 3 for the gas LDC sample, the results from the long-term risk positioning model (ECAPM with $\alpha = 0.5$), the average ATWACC for the full sample is 7.7 percent, with a corresponding cost of equity estimate of 11.3 percent for the full sample and 7.9 and 11.6 percent for the sub-sample. Although I do not give much weight to the DCF estimates, I note that those estimates for the more reliable multistage model are lower at 10.3 percent for the sub-sample.

Based upon consideration of all of the sample evidence, the best point estimate for the cost of equity for NorthWestern's SD operations is 11¼ percent. Given the results of the cost of capital estimation models, this is a conservation estimate because this value is about ½ percent lower than the average risk positioning results for the sub-sample when using the long-term risk-free rate, but it is also about 1 percent higher than the multistage DCF estimates. As noted earlier, I do not believe that the DCF estimates are completely reliable for the industry at this time. In addition, the point estimate is about ½ percent lower than the results from the short-term version of the risk positioning model for the full sample. However, it is more correct to say that the estimates from the sample provide a range of values from a low of 10¾ percent to a high of 11¾ percent.

Q54. Does this conclude your testimony?

A54. Yes.

APPENDIX A

RESUMÉ

MICHAEL J. VILBERT **PRINCIPAL**

Michael Vilbert is an expert in cost of capital, financial planning and valuation who has advised clients on these matters in the context of a wide variety of investment and regulatory decisions. He received his Ph.D. in Financial Economics from the Wharton School of the University of Pennsylvania, an MBA from the University of Utah, an M.S. from the Fletcher School of Law and Diplomacy, Tufts University, and a B.S. degree from the United States Air Force Academy. He joined The Brattle Group in 1994 after a career as an Air Force officer, where he served as a fighter pilot, intelligence officer, and professor of finance at the Air Force Academy.

REPRESENTATIVE CONSULTING EXPERIENCE

- In a securities fraud case, Dr. Vilbert designed and created a model to value the private placement stock of a drug store chain as if there had been full disclosure of the actual financial condition of the firm. He analyzed key financial data and security analyst's reports regarding the future of the industry in order to recreate pro forma balance sheet and income statements under a variety of scenarios designed to establish the value of the firm.

- For pharmaceutical companies rebutting price-fixing claims in antitrust litigation, Dr. Vilbert was a member of a team which prepared a comprehensive analysis of industry profitability. The analysis replicated, tested and critiqued the major recent analyses of drug costs, risks and returns. The analyses helped develop expert witness testimony to rebut allegations of excess profits.

- For an independent electric power producer, Dr. Vilbert created a model that analyzed the reasonableness of rates and costs filed by a natural gas pipeline. The model not only duplicated the pipeline's rates, but it also allowed simulation of a variety of "what if" scenarios associated with cost recovery under alternative time patterns and joint cost allocations. Results of the analysis were adopted by the intervenor group for negotiation with the pipeline.

- For the CFO of an electric utility, Dr. Vilbert developed the valuation model used to support a stranded cost estimation filing. The case involved a conflict between two utilities over the responsibility for out-of-market costs associated with a power purchase contract between them. In addition, he advised and analyzed cost recovery mechanisms that would allow full recovery of the stranded costs while providing a rate reduction for the company's rate payers.

- Dr. Vilbert has assisted in the preparation of testimony and the development of estimation models in numerous cost of capital cases for natural gas pipeline, water utility and electric utility clients before the Federal Energy Regulatory Commission ("FERC") and state regulatory commissions. These have spanned standard estimation techniques (e.g., Discounted Cash Flow and Risk Positioning models). He has also developed and applied more advanced models specific to the industries or lines of business in question, e.g., based on the structure and risk characteristics of cash flows, or based on multi-factor models that better characterize regulated industries.

- Dr. Vilbert has valued several large, residual oil-fired generating stations to evaluate the possible conversion to natural gas or other fuels. In these analyses, the expected pre- and post-conversion station values were computed using a range of market electricity and fuel cost conditions.

- For a major western electric utility, Dr. Vilbert helped prepare testimony that analyzed the prudence of QF contract enforcement. The testimony demonstrated that the utility had not been compensated in its allowed cost of capital for major disallowances stemming from QF contract management.

- Dr. Vilbert analyzed the economic need for a major natural gas pipeline expansion to the Midwest. This involved evaluating forecasts of natural gas use in various regions of the United States and the effect of additional supplies on the pattern of natural gas pipeline use. The analysis was used to justify the expansion before the FERC and the National Energy Board of Canada.

- For a Public Utility Commission in the Northeast, Dr. Vilbert analyzed the auction of an electric utilities purchase power agreements to determine whether the outcome of the auction was in the ratepayers' interest. The work involved the analysis of the auction procedures as well as the benefits to ratepayers of transferring risk of the PPA payments to the buyer.

- Dr. Vilbert led a team tasked to determine whether bridge tolls were "just and reasonable" for a non-profit port authority. Determination of the cost of service for the authority required estimation of the value of the authority's assets using the trended original cost methodology as well as evaluation of the operations and maintenance budgets. Investment costs, bridge traffic information and inflation indices covering a 75 year period were utilized to estimate the value of four bridges and a passenger transit line valued in excess of $1 billion.

- Dr. Vilbert helped a recently privatized railroad in Brazil develop an estimate of its revenue requirements, including a determination of the railroad's cost of capital. He also helped evaluate alternative rate structures designed to provide economic incentives to shippers as well as to the railroad for improved service. This involved the explanation and analysis of the contribution margin of numerous shipper products, improved cost analysis and evaluation of bottlenecks in the system.

- For a utility in the Southeast, Dr. Vilbert quantified the company's stranded costs under several legislative electric restructuring scenarios. This involved the evaluation of all of the company's fossil and nuclear generating units, its contracts with Qualifying Facilities and the prudence of those QF contracts. He provided analysis concerning the impact of securitizing the company's stranded costs as a means of reducing the cost to the rate payers and several alternative designs for recovering stranded costs.

- For a recently privatized electric utility in Australia, Dr. Vilbert evaluated the proposed regulatory scheme of the Australian Competition and Consumer Commission for the company's electric transmission system. The evaluation highlighted the elements of the proposed regulation which would impose uncompensated asymmetric risks on the company and the need to either eliminate the asymmetry in risk or provide additional compensation so that the company could expect to earn its cost of capital.

- For an electric utility in the Southwest, Dr. Vilbert helped design and create a model to estimate the stranded costs of the company's portfolio of Qualifying Facilities and Power Purchase contracts. This exercise was complicated by the many variations in the provisions of the contracts that required modeling in order to capture the effect of changes in either the performance of the plants or in the estimated market price of electricity.

- Dr. Vilbert helped prepare the testimony responding to a FERC request for further comments on the appropriate return on equity for electric transmission facilities. In addition, Dr. Vilbert was a member of the team that made a presentation to the FERC staff on the expected risks of the unbundled electric transmission line of business.

- Dr. Vilbert and Mr. Frank C. Graves, also of The Brattle Group, prepared testimony evaluating an innovative Canadian stranded cost recovery procedure involving the auctioning of the output of the province's electric generation plants instead of the plants themselves. The evaluation required the analysis of the terms and conditions of the long-term contracts specifying the revenue requirements of the plants for their entire forecasted remaining economic life and required an estimate of the cost of capital for the plant owners under this new stranded cost recovery concept.

- Dr. Vilbert served as the neutral arbitrator for the valuation of a petroleum products tanker. The valuation required analysis of the Jones Act tanker market and the supply and demand balance of the available U.S. constructed tanker fleet.

PRESENTATIONS

"Utility Distribution Cost of Capital," *EEI Electric Rates Advanced Course*, Bloomington, IN, 2002, 2003.

"Issues for Cost of Capital Estimation," with Bente Villadsen, *Edison Electric Institute Cost of Capital Conference*, Chicago, IL, February 2004.

"Not Your Father's Rate of Return Methodology," *Utility Commissioners/Wall Street Dialogue*, NY, May 2004.

"Current Issues in Cost of Capital," *EEI Electric Rates Advanced Course*, Madison, WI, July 2004.

"Cost of Capital Estimation: Issues and Answers," *MidAmerican Regulatory Finance Conference*, Des Moines, IA, April 7, 2005.

"Cost of Capital - Explaining to the Commission - Different ROEs for Different Parts of the Business," *EEI Economic Regulation & Competition Analysts Meeting*, May 2, 2005.

"Current Issues in Cost of Capital," with Bente Villadsen, *EEI Electric Rates Advanced Course*, Madison, WI, 2005.

"Current Issues in Estimating the Cost of Capital," *EEI Electric Rates Advanced Course*, Madison, WI, 2006.

"Revisiting the Development of Proxy Groups and Relative Risk Analysis," Society of Utility and Regulatory Financial Analysts: 39th Financial Forum, April 2007.

ARTICLES

"Flaws in the Proposed IRS Rule to Reinstate Amortization of Deferred Tax Balances Associated with Generation Assets Reorganized in Industry Restructuring," by Frank C. Graves and Michael J. Vilbert, white paper for *Edison Electric Institute* (EEI) to the IRS, July 25, 2003.

"The Effect of Debt on the Cost of Equity in a Regulatory Setting," by A. Lawrence Kolbe, Michael J. Vilbert, Bente Villadsen and The Brattle Group, *Edison Electric Institute*, April 2005.

"Measuring Return on Equity Correctly: Why current estimation models set allowed ROE too low," by A. Lawrence Kolbe, Michael J. Vilbert and Bente Villadsen, *Public Utilities Fortnightly*, August 2005.

"Understanding Debt Imputation Issues," by Michael J. Vilbert, Bente Villadsen and Joseph B. Wharton, *Edison Electric Institute*, forthcoming May 2007.

TESTIMONY

Direct and rebuttal testimony before the Alberta Energy and Utilities Board on behalf of TransAlta Utilities Corporation in the matter of an application for approval of its 1999 and 2000 generation tariff, transmission tariff, and distribution revenue requirement, October 1998.

Direct testimony before the Federal Energy Regulatory Commission on behalf of Central Maine Power in Docket No. ER00-982-000, December 1999.

Direct testimony before the Alberta Energy and Utilities Board on behalf of TransAlta Utilities Corporation for approval of its 2001 transmission tariff, May 2000.

Direct testimony before the Federal Energy Regulatory Commission on behalf of Mississippi River Transmission Corporation in Docket No. RP01-292-000, March 2001.

Written evidence, rebuttal, reply and further reply before the National Energy Board in the matter of an application by TransCanada PipeLines Limited for orders pursuant to Part I and Part IV of the *National Energy Board Act*, Order AO-1-RH-4-2001, May 2001, Nov. 2001, Feb. 2002.

Written evidence before the Public Utility Board on behalf of Newfoundland & Labrador Hydro - Rate Hearings, October 2001.

Direct testimony (with Bill Lindsay) before the Federal Energy Regulatory Commission on behalf of DTE East China, LLC in Docket No. ER02-1599-000, April 2002.

Direct and rebuttal reports before the Arbitration Panel in the arbitration of stranded costs for the City of Casselberry, FL, Case No. 00-CA-1107-16-L, July 2002.

Direct reports before the Arbitration Board for Petroleum products trade in the Arbitration of the Military Sealift Command vs. Household Commercial Financial Services, fair value of sale of the Darnell, October 2002.

Direct testimony and hearing before the Arbitration Panel in the arbitration of stranded costs for the City of Winter Park, FL, In the Circuit Court of the Ninth Judicial Circuit in and for Orange County, FL, Case No. C1-01-4558-39, December 2002.

Direct testimony before the Federal Energy Regulatory Commission on behalf of Florida Power Corporation, dba Progress Energy Florida, Inc. in Docket No. SC03-___-000, March 2003.

Direct report before the Arbitration Panel in the arbitration of stranded costs for the Town of Belleair, FL, Case No. 000-6487-C1-007, April 2003.

Direct and rebuttal reports before the Alberta Energy and Utilities Board in the matter of the Alberta Energy and Utilities Board Act, R.S.A. 2000, c. A-17, and the Regulations under it; in the matter of the Gas Utilities Act, R.S.A. 2000, c. G-5, and the Regulations under it; in the matter of the Public utilities Board Act, R.S.A. 2000, c. P-45, as amended, and the Regulations under it; and in the matter of Alberta Energy and Utilities Generic Cost of Capital Hearing, Proceeding No. 1271597, July 2003, November 2003.

Written evidence before the National Energy Board in the matter of the National Energy Board Act, R.S.C. 1985, c. N–7, as amended, (Act) and the Regulations made under it; and in the matter of an application by TransCanada PipeLines Limited for orders pursuant to Part IV of the *National Energy Board Act*, for approval of Mainline Tolls for 2004, RH-2-2004, January 2004.

Direct and rebuttal testimony before the Public Service Commission of West Virginia, on Cost of Capital for West Virginia-American Water Company, Case No 04-0373-W-42T, May 2004.

Direct and rebuttal testimony before the Federal Energy Regulatory Commission, on Energy Allocation of Debt Cost for Incremental Shipping Rates for Edison Mission Energy, Docket No. RP04-274-000, December 2004 and March 2005.

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Direct testimony before the Federal Energy Regulatory Commission, Docket No. ER07-46-000, on behalf of Northwestern Corporation on the Cost of Capital for Transmission Assets, October 2006.

Direct and rebuttal testimony before the Tennessee Regulatory Authority, Case No. 06-00290, on behalf of Tennessee American Water Company, on the Cost of Capital, November, 2006 and April 2007.

APPENDIX B

SELECTING THE GAS LDC SAMPLE AND USE OF MARKET VALUES

I. SAMPLE SELECTION AND THE SAMPLE'S CHARACTERISTICS

Q1. How do you select the U.S. gas LDC sample?

A1. To select this sample, I started with the universe of publicly traded natural gas distribution utilities covered by *Value Line Investment Survey Plus*. This resulted in an initial group of 23 companies, to which I added Vectren Corporation because it is often viewed as a natural gas LDC. Vectren is involved in both gas and electric distribution activities, but more of its regulated assets are invested in the gas distribution operations.[1] This company is also covered by *Value Line*, but is classified as an Electric Utility due to its regulated electric operations.[2] I then eliminated companies by applying additional selection criteria designed to remove companies with unique circumstances which may bias the cost of capital estimates. The final sample consists of nine gas LDCs, from which I also consider a sub-sample of four companies with the fewest reliability concerns. Table No. MJV-2 reports the estimated share of total assets for each company devoted to regulated activities in 2006.

Q2. What are the other selection criteria you applied?

A2. Companies were first eliminated if their operating regions were outside of the continental USA. I then applied my standard selection criteria to narrow the sample to those companies likely to have reliable cost of equity estimates. Specifically, I eliminated all companies whose S&P bond rating as reported by Bloomberg was not investment grade, i.e., less than BBB-. To guard against measurement bias caused by "thin trading," I also restricted the sample to companies with total operating revenues greater than $300 million (USD) in 2006 as reported by Bloomberg.[3] Companies that had a large merger

[1] Vectren Utility Holdings, Inc.'s 2006 10K reveals that about 57 percent of its assets are regulated natural gas distribution assets and 37 percent are regulated electric assets. Because it has a substantial amount of regulated electric activity, I exclude it from the sub-sample of companies I consider to be the most representative of the natural gas distribution line of business and to be most free of characteristics that may bias cost of equity estimates.

[2] The 24 companies are from *Value Line Investment Survey Plus*, reviewed March 9, 2007.

[3] Data was reviewed during the first week of April 2007.

during the period January 2004 to April 2007 (i.e., just over the past three years) were also generally removed from the sample, although two companies which would otherwise not survive the process were included since their primary merger activity occurred in 2004. These two companies were Atmos Energy and AGL Resources, and they were subsequently excluded from a sub-sample of *cleanest* companies I also considered as part of my analysis. The screen for merger activity was primarily done by scanning each company's news history on Bloomberg and a search of company web pages.[4]

Finally, I required that the companies have historical data available from Bloomberg for the relevant period and had no dividend cuts or restatement of financial statements in the past five years, since the latter can be signs of financial distress.

Q3. Please elaborate on how companies were eliminated from your sample?

A3. Six companies were immediately eliminated due to a lack of long-term earnings per share ("EPS") growth rate estimates from Bloomberg. Of these, five also experienced dividend cuts and had either no bond rating or were rated less than BBB-. From the remaining companies, three were not rated and one had a rating of B+. Keyspan Corp. was eliminated for high levels of merger and acquisition activity ("M&A") and recent dividend cuts. UGI Corp. was removed for high levels of merger activity, and because it primarily sells propane which is not regulated. Southern Union was eliminated for its unusually high levels of M&A activity. Nicor Inc. was eliminated from the sample because it restated earnings for 1999-2001 and because it settled regulatory compliance issues with the Federal Energy Regulatory Commission ("FERC") in 2003.[5] Finally, New Jersey Resources was eliminated because of a very high percentage of revenues from other comprehensive income.

[4] Company web pages were searched in December 2003 for merger and acquisition activities during the 2001-2003 period, in July 2006 for merger and acquisition activities during the period 2004 through July 2006, and in December 2006 for the period August through December 2006.

[5] Nicor announced on October 29, 2002 that its earnings for 1999-2001 would be revised downwards by $15-35 million. March 4, 2003, Nicor released its restated earnings for 1999-2001 along with 2002 earnings.

Q4. Are there any issues with the remaining companies in your sample?

A4. Perhaps. Several companies in the sample engage in natural gas marketing activities (see Table 2 in the MJV Direct Testimony).[6] Given the turmoil of the energy trading markets, the companies' cost of capital estimates may be more volatile than those of more stable companies. Although still investment grade, Southwest Gas is at the bottom of the scale of investment grade credit ratings and has a relatively low average equity thickness over the past five years – 40.1 percent compared to 61.8 percent for the remaining companies. Closer investigation shows that Southwest Gas's capital structure has been shifting rapidly towards equity over the last five years, with a level of about 50 percent over the most recent two years. These factors suggest a potential reliability problem for estimates of this company's cost of capital at this time. The Laclede Group's market cap of $688 million is a bit smaller than the average of the group, but with revenues of more than $1.5 billion, it is still a large company. In 2006, Piedmont Natural Gas restated some portions of its 2003-2005 financial reports. Although this can generally lead to less reliable estimates from the equity estimation models, the restatements were not caused by fraudulent activities but were due to an accounting error in the classification of hedging amounts. This type of reclassification would not be expected to change the value of the firm and prices did not show any erratic behavior in the period surrounding the announcement of this reclassification. A potential concern for the DCF estimates is that the industry has experienced a sustained level of merger and acquisition activity over the last five years that has implication for the stability of the industry necessary for the reliable application of the DCF model. Due to the concerns with the sample, I also report the results for a sub-sample of the gas LDC sample that consists of companies with no material data issues.

[6] The percentages of regulated assets calculated for the samples are only estimates due to data reporting limitations.

Q5. Please compare the relative risk of the sample with respect to NorthWestern's SD operations.

A5. The sample consists of nine gas LDCs with generally similar risk characteristics to those of NorthWestern's SD gas operations (see Table 3 in the MJV Direct Testimony). Like NorthWestern's SD operations, they all have fuel-cost adjustment clauses which significantly reduce exposure to this risk. In their 10-Ks, all sample companies report that they engage in hedging activities to further reduce this risk. In addition, seven of the nine companies have weather adjustment clauses, but NorthWestern's SD operations does not have such a provision. The sample evidences a high degree of regulated activities, with the estimated share of regulated assets averaging about 87 percent across the companies in 2006 (see Table No. MJV-2). For the sub-sample, the percentage of regulated assets is even higher at 96 percent. As mentioned earlier in my direct testimony, Vectren Corp. earns a significant amount of its income from regulated electric activities despite being very active in the regulated gas LDC line of business. As such, it may be considered to be of slightly different business risk than the rest of the sample.[7]

Q6. What companies are in the sub-sample?

A6. The sub-sample consists of Laclede Group, Northwest Natural Gas, Piedmont Natural Gas and WGL Holdings. Vectren was eliminated because of its mix of both regulated natural gas and regulated electric operations. Atmos Energy and AGL Resources were eliminated because of M&A activities in 2004, and South Jersey Industries was eliminated from the sub-sample because of the accounting restatements.

Q7. What do you conclude from the comparison of the sample companies to NorthWestern's SD operations?

A7. I believe that the sample of regulated gas utility companies has business risk that is comparable on average to that of NorthWestern's SD gas operations.

[7] Vectron was excluded from the sub-sample for this reason.

II. MARKET VALUE CAPITAL STRUCTURE, COSTS OF DEBT & COSTS OF PREFERRED EQUITY

Q8. What capital structure information do you require?

A8. For reasons discussed in my written evidence and explained in detail in Appendix E, explicit evaluation of the market-value capital structures of the sample companies versus the capital structure used for rate making is vital for a correct interpretation of the market evidence. This requires estimates of the market values of common and preferred equity and debt, and the current market costs of preferred equity and debt.

Q9. How do you calculate the market-value capital structures of the sample companies?

A9. I estimate the capital structure for each company by estimating the market values of common equity, preferred equity and debt from publicly available data. The calculations are in Panels A to I of Table No. MJV-3.

The market value of equity is straightforward: the price per share times the number of shares outstanding. The market value of preferred is set equal to its book value because the portion of the capital structure financed with preferred equity is generally small. The market value of debt is estimated at the book value of debt reported by Bloomberg plus or minus the difference in the estimated fair (market) value and book value of long-term debt as reported in the companies' 10-Ks or annual reports.[8]

For purposes of assessing financial risk to common shareholders, I add an adjustment for short-term debt to the debt portion of the capital structure. This adjustment is used only for those companies whose short-term (current) liabilities exceed their short-term (current) assets. I add an amount equal to the minimum of the difference between short-term liabilities and short-term assets or the amount of short-term debt. The reason for this adjustment is to recognize that when current liabilities exceed current

[8] See Panels A through I in Table No. MJV-3 for details. The adjustment relies on the difference between the companies' self-reported fair value of long-term debt and the carrying value of the same line items. This information was obtained from the sample companies' annual reports.

assets, a portion of the companies long-term assets are being financed, in effect, by short-term debt.

The market value capital structure is calculated to be consistent with the time period over which the cost of capital is estimated for the sample. The capital structure is determined over the historical period over which the relevant risk positioning parameters were determined and as of the date analysts provide forward looking growth forecasts. Therefore, Table No. MJV-3 reports the market value capital structure at year end for the years ending 2002 - 2006. The output of these tables is the market equity-to-value, debt-to-value, and preferred equity-to-value ratios. The overall cost of capital calculation for the gas LDC risk positioning estimates rely on the average of the market value capital structure computed for the years 2002 through 2006 as shown in Table No. MJV-4. The results in columns [1]-[3] are used in the DCF model calculations, while columns [4]-[6] are for the risk positioning models.

Q10. How do you estimate the current market cost of preferred equity?

A10. For companies with preferred equity, the cost of preferred equity for each company was set equal to the yield on an index of preferred stock as reported in the Mergent Bond Record corresponding to the S&P rating of that company's debt. The yields from Mergent were as of March 10, 2007. In general, the average amount of preferred equity in the sample companies' capital structures is very small and frequently zero. No company has more than two percent on average.[9]

Q11. How do you estimate the current market cost of debt?

A11. The market cost of debt for each company in the DCF analysis is the current yield reported by Bloomberg for a public utility company bond corresponding to the sample company's current debt rating as classified by S&P. The risk positioning analysis, on the other hand, uses the current yield of a utility bond that corresponds to the five-year average debt rating of each company so as to match consistently the horizon of

[9] NorthWestern itself has no preferred securities in its regulatory capital structure.

information used by *Value Line* to estimate company betas. The current S&P debt ratings were obtained from Bloomberg.

Bloomberg reports that as of March 27, 2007, the average yield on A-rated Public Utility bonds was 5.85 percent, and 6.11 percent on average for BBB-rated Public Utility bonds.[10] (See Panel C of Workpaper #1 to Table No. MJV-11 for the yields on utility bonds and preferred stock by credit rating.) Calculation of the after-tax cost of debt uses the current federal corporate marginal tax rate of 35 percent, since South Dakota does not currently collect corporate level taxes.

[10] All companies in the U.S. gas LDC samples are either BBB or A rated except WGL Holdings which is AA-rated. The yield on AA-rated utility bonds is calculated as the yield on A-rated utility bonds minus ½ times the spread between the yield on BBB and A rated utility bonds.

Table No. MJV-1

Index to Tables for the Written Evidence of Michael J. Vilbert

Table No. MJV-2

MJV US Gas LDC Sample

Estimated Percentage of Regulated Assets in 2006

	Atmos Energy Corp	Laclede Group Inc/The	Northwest Natural Gas Co	Piedmont Natural Gas Co	South Jersey Industries Inc	Southwest Gas Corp	WGL Holdings Inc	AGL Resources Inc	Vectren Corp	Full Sample Average	Sub Sample Average
		*	*	*			*				
% Regulated Assets	95.5%	89.5%	98.0%	97.2%	78.1%	96.2%	99.8%	74.3%	93.9%	91.4%	96.1%

Sources and Notes:
Workpaper #1 to Table No. MJV-2, Panels A-I.
* Represents companies included in the subsample.

Table No. MJV-3

Market Value of the MJV US Gas LDC Sample

Panel A: Atmos Energy Corp

($MM)

	DCF Capital Structure	Year End, 2006	Year End, 2005	Year End, 2004	Year End, 2003	Year End, 2002	Notes
MARKET VALUE OF COMMON EQUITY							
Book Value, Common Shareholder's Equity	$1,648	$1,648	$1,602	$1,133	$858	$573	[a]
Shares Outstanding (in millions) - Common	82	82	81	63	51	42	[b]
Price per Share - Common	$32	$32	$26	$27	$25	$23	[c]
Market Value of Common Equity	$2,584	$2,622	$2,105	$1,714	$1,273	$974	[d] = [b] x [c].
Market to Book Value of Common Equity	1.57	1.59	1.31	1.51	1.48	1.70	[e] = [d] / [a].
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	[f]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	[g] = [f].
MARKET VALUE OF DEBT							
Current Assets	$1,118	$1,118	$1,264	$677	$458	$331	[h]
Current Liabilities	$1,119	$1,119	$1,113	$414	$442	$464	[i]
Current Portion of Long-Term Debt	$3	$3	$3	$6	$9	$22	[j]
Net Working Capital	$2	$2	$155	$269	$26	($111)	[k] = [h] - ([i] - [j]).
Notes Payable (Short-Term Debt)	$382	$382	$145	$0	$119	$146	[l]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$111	[m] = See Sources and Notes.
Long-Term Debt	$2,180	$2,180	$2,183	$861	$863	$670	[n]
Book Value of Long-Term Debt	$2,184	$2,184	$2,186	$867	$872	$804	[o] = [n] − [j] + [m].
Adjustment to Book Value of Long-Term Debt	($126)	($126)	($105)	$75	$141	$105	[p] = See Sources and Notes.
Market Value of Long-Term Debt	$2,057	$2,057	$2,082	$943	$1,013	$909	[q] = [p] − [o].
Market Value of Debt	$2,057	$2,057	$2,082	$943	$1,013	$909	[r] = [q].
MARKET VALUE OF FIRM							
	$4,641	$4,679	$4,186	$2,657	$2,286	$1,882	[s] = [d] + [g] + [r].
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	55.68%	56.04%	50.28%	64.52%	55.68%	51.73%	[t] = [d] / [s].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	[u] = [g] / [s].
Debt - Market Value Ratio	44.32%	43.96%	49.72%	35.48%	44.32%	48.27%	[v] = [r] / [s].

Sources and Notes:

Bloomberg as of April 09, 2007

Capital structure from Year End, 2006 calculated using respective balance sheet information and 5-day average prices ending at period end.

The DCF Capital structure is calculated using 4th Quarter, 2006 balance sheet information and a 15-trading day average closing price ending on 4/9/2007.
Prices are reported in Workpaper #1 to Table No. MJV-6.

[m] =
(1): 0 if [k] > 0.
(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].
(3): [l] if [k] < 0 and |[k]| > [l]

[p]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2006 10-K.

Table No. MJV-3

Market Value of the MJV US Gas LDC Sample

Panel B: Laclede Group Inc/The

($MM)

	DCF Capital Structure	Year End, 2006	Year End, 2005	Year End, 2004	Year End, 2003	Year End, 2002	Notes
MARKET VALUE OF COMMON EQUITY							
Book Value, Common Shareholder's Equity	$403	$403	$367	$356	$299	$286	[a]
Shares Outstanding (in millions) - Common	21	21	21	21	19	19	[b]
Price per Share - Common	$31	$35	$29	$31	$29	$24	[c]
Market Value of Common Equity	$666	$753	$624	$654	$560	$458	[d] = [b] x [c].
Market to Book Value of Common Equity	1.65	1.87	1.70	1.84	1.87	1.60	[e] = [d] / [a].
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	$1	$1	$1	$1	$1	$1	[f]
Market Value of Preferred Equity	$1	$1	$1	$1	$1	$1	[g] = [f].
MARKET VALUE OF DEBT							
Current Assets	$460	$460	$424	$338	$288	$222	[h]
Current Liabilities	$431	$431	$366	$263	$366	$337	[i]
Current Portion of Long-Term Debt	$0	$0	$40	$25	$0	$25	[j]
Net Working Capital	$29	$29	$99	$100	($78)	($89)	[k] = [h] - ([i] - [j]).
Notes Payable (Short-Term Debt)	$207	$207	$71	$71	$218	$162	[l]
Adjusted Short-Term Debt	$0	$0	$0	$0	$78	$89	[m] = See Sources and Notes.
Long-Term Debt	$395	$395	$340	$380	$305	$260	[n]
Book Value of Long-Term Debt	$396	$396	$380	$405	$383	$374	[o] = [n] + [j] + [m].
Adjustment to Book Value of Long-Term Debt	$18	$18	$31	$35	$31	$31	[p] = See Sources and Notes.
Market Value of Long-Term Debt	$414	$414	$412	$440	$414	$405	[q] = [p] + [o].
Market Value of Debt	$414	$414	$412	$440	$414	$405	[r] = [q].
MARKET VALUE OF FIRM							
	$1,081	$1,168	$1,037	$1,096	$975	$864	[s] = [d] + [g] + [r].
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	61.62%	64.48%	60.21%	59.72%	57.39%	53.01%	[t] = [d] / [s].
Preferred Equity - Market Value Ratio	0.07%	0.07%	0.09%	0.10%	0.13%	0.15%	[u] = [g] / [s].
Debt - Market Value Ratio	38.31%	35.45%	39.70%	40.18%	42.48%	46.85%	[v] = [r] / [s].

Sources and Notes:

Bloomberg as of April 09, 2007

Capital structure from Year End, 2006 calculated using respective balance sheet information and 5-day average prices ending at period end.

The DCF Capital structure is calculated using 4th Quarter, 2006 balance sheet information and a 15-trading day average closing price ending on 4/9/2007.
Prices are reported in Workpaper #1 to Table No. MJV-6.

[m] =

(1): 0 if [k] > 0.

(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].

(3): [l] if [k] < 0 and |[k]| > [l].

[p]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2006 10-K.

Table No. MJV-3

Market Value of the MJV US Gas LDC Sample

Panel C: Northwest Natural Gas Co

($MM)

	DCF Capital Structure	Year End, 2006	Year End, 2005	Year End, 2004	Year End, 2003	Year End, 2002	Notes
MARKET VALUE OF COMMON EQUITY							
Book Value, Common Shareholder's Equity	$600	$600	$587	$569	$506	$482	[a]
Shares Outstanding (in millions) - Common	27	27	28	27	26	26	[b]
Price per Share - Common	$46	$43	$35	$34	$31	$27	[c]
Market Value of Common Equity	$1,252	$1,161	$953	$910	$806	$695	[d] = [b] x [c].
Market to Book Value of Common Equity	2.09	1.94	1.62	1.60	1.59	1.44	[e] = [d] / [a].
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$8	[f]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$8	[g] = [f].
MARKET VALUE OF DEBT							
Current Assets	$309	$309	$324	$237	$200	$193	[h]
Current Liabilities	$339	$339	$327	$267	$214	$205	[i]
Current Portion of Long-Term Debt	$30	$30	$8	$15	$0	$20	[j]
Net Working Capital	($1)	($1)	$5	($15)	($15)	$8	[k] = [h] - ([i] - [j]).
Notes Payable (Short-Term Debt)	$100	$100	$127	$103	$85	$70	[l]
Adjusted Short-Term Debt	$1	$1	$0	$15	$15	$0	[m] = See Sources and Notes.
Long-Term Debt	$517	$517	$522	$484	$500	$446	[n]
Book Value of Long-Term Debt	$548	$548	$530	$514	$515	$466	[o] = [n] + [j] + [m].
Adjustment to Book Value of Long-Term Debt	$49	$49	$50	$69	$62	$53	[p] = See Sources and Notes.
Market Value of Long-Term Debt	$597	$597	$579	$583	$578	$518	[q] = [p] + [o].
Market Value of Debt	$597	$597	$579	$583	$578	$518	[r] = [q]
MARKET VALUE OF FIRM							
	$1,849	$1,757	$1,532	$1,493	$1,383	$1,222	[s] = [d] + [g] + [r].
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	67.73%	66.04%	62.18%	60.94%	58.25%	56.90%	[t] = [d] / [s].
Preferred Equity - Market Value Ratio	-	-	-	-	-	0.67%	[u] = [g] / [s].
Debt - Market Value Ratio	32.27%	33.96%	37.82%	39.06%	41.75%	42.42%	[v] = [r] / [s].

Sources and Notes:
Bloomberg as of April 09, 2007
Capital structure from Year End, 2006 calculated using respective balance sheet information and 5-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2006 balance sheet information and a 15-trading day average closing price ending on 4/9/2007.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[m] =
(1): 0 if [k] > 0.
(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].
(3): [l] if [k] < 0 and |[k]| > [l].
[p]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2006 10-K.

Table No. MJV-3

Market Value of the MJV US Gas LDC Sample

Panel D: Piedmont Natural Gas Co

($MM)

	DCF Capital Structure	Year End, 2006	Year End, 2005	Year End, 2004	Year End, 2003	Year End, 2002	Notes
MARKET VALUE OF COMMON EQUITY							
Book Value, Common Shareholder's Equity	$883	$883	$884	$855	$630	$590	[a]
Shares Outstanding (in millions) - Common	75	75	77	77	67	66	[b]
Price per Share - Common	$27	$27	$24	$23	$22	$18	[c]
Market Value of Common Equity	$1,994	$2,022	$1,842	$1,784	$1,459	$1,187	[d] = [b] x [c].
Market to Book Value of Common Equity	2.26	2.29	2.08	2.09	2.31	2.01	[e] = [d] / [a].
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	[f]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	[g] = [f].
MARKET VALUE OF DEBT							
Current Assets	$476	$476	$505	$391	$323	$176	[h]
Current Liabilities	$400	$400	$529	$336	$740	$205	[i]
Current Portion of Long-Term Debt	$0	$0	$35	$0	$2	$47	[j]
Net Working Capital	$76	$76	$11	$55	($414)	$18	[k] = [h] - ([i] - [j]).
Notes Payable (Short-Term Debt)	$170	$170	$159	$110	$555	$47	[l]
Adjusted Short-Term Debt	$0	$0	$0	$0	$414	$0	[m] = See Sources and Notes.
Long-Term Debt	$825	$825	$625	$660	$460	$462	[n]
Book Value of Long-Term Debt	$825	$825	$660	$660	$876	$509	[o] = [n] + [j] + [m].
Adjustment to Book Value of Long-Term Debt	$89	$89	$93	$115	$45	$81	[p] = See Sources and Notes.
Market Value of Long-Term Debt	$914	$914	$753	$775	$921	$590	[q] = [p] + [o].
Market Value of Debt	$914	$914	$753	$775	$921	$590	[r] = [q].
MARKET VALUE OF FIRM							
	$2,907	$2,935	$2,595	$2,559	$2,380	$1,776	[s] = [d] + [g] + [r].
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	68.57%	68.87%	70.98%	69.71%	61.29%	66.81%	[t] = [d] / [s].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	[u] = [g] / [s].
Debt - Market Value Ratio	31.43%	31.13%	29.02%	30.29%	38.71%	33.19%	[v] = [r] / [s].

Sources and Notes:
Bloomberg as of April 09, 2007
Capital structure from Year End, 2006 calculated using respective balance sheet information and 5-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2006 balance sheet information and a 15-trading day average closing price ending on 4/9/2007.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[m] =
(1): 0 if [k] > 0.
(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].
(3): [l] if [k] < 0 and |[k]| > [l].
[p]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2006 10-K.

Table No. MJV-3

Market Value of the MJV US Gas LDC Sample

Panel E: South Jersey Industries Inc

($MM)

	DCF Capital Structure	Year End, 2006	Year End, 2005	Year End, 2004	Year End, 2003	Year End, 2002	Notes
MARKET VALUE OF COMMON EQUITY							
Book Value, Common Shareholder's Equity	$443	$443	$394	$343	$298	$238	[a]
Shares Outstanding (in millions) - Common	29	29	29	28	26	24	[b]
Price per Share - Common	$38	$33	$29	$26	$20	$17	[c]
Market Value of Common Equity	$1,116	$981	$854	$728	$535	$404	[d] = [b] x [c].
Market to Book Value of Common Equity	2.52	2.21	2.17	2.12	1.79	1.70	[e] = [d] / [a].
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	$0	$0	$0	$2	$2	$2	[f]
Market Value of Preferred Equity	$0	$0	$0	$2	$2	$2	[g] = [f].
MARKET VALUE OF DEBT							
Current Assets	$372	$372	$362	$284	$266	$212	[h]
Current Liabilities	$423	$423	$406	$285	$268	$316	[i]
Current Portion of Long-Term Debt	$2	$2	$2	$5	$5	$11	[j]
Net Working Capital	($49)	($49)	($42)	$4	$3	($93)	[k] = [h] - ([i] - [j]).
Notes Payable (Short-Term Debt)	$195	$195	$147	$92	$113	$167	[l]
Adjusted Short-Term Debt	$49	$49	$42	$0	$0	$93	[m] = See Sources and Notes.
Long-Term Debt	$358	$358	$319	$329	$309	$274	[n]
Book Value of Long-Term Debt	$409	$409	$363	$334	$314	$378	[o] = [n] + [j] + [m].
Adjustment to Book Value of Long-Term Debt	$21	$21	$13	$16	$25	$43	[p] = See Sources and Notes.
Market Value of Long-Term Debt	$430	$430	$376	$350	$339	$421	[q] = [p] + [o].
Market Value of Debt	$430	$430	$376	$350	$339	$421	[r] = [q].
MARKET VALUE OF FIRM							
	$1,546	$1,411	$1,230	$1,080	$875	$826	[s] = [d] + [g] + [r].
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	72.20%	69.54%	69.42%	67.42%	61.11%	48.85%	[t] = [d] / [s].
Preferred Equity - Market Value Ratio	-	-	-	0.16%	0.19%	0.20%	[u] = [g] / [s].
Debt - Market Value Ratio	27.80%	30.46%	30.58%	32.42%	38.70%	50.95%	[v] = [r] / [s].

Sources and Notes:

Bloomberg as of April 09, 2007

Capital structure from Year End, 2006 calculated using respective balance sheet information and 5-day average prices ending at period end.

The DCF Capital structure is calculated using 4th Quarter, 2006 balance sheet information and a 15-trading day average closing price ending on 4/9/2007.
Prices are reported in Workpaper #1 to Table No. MJV-6.

[m] =
(1): 0 if [k] > 0.
(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].
(3): [l] if [k] < 0 and |[k]| > [l].

[p]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2006 10-K.

Table No. MJV-3

Market Value of the MJV US Gas LDC Sample

Panel F: Southwest Gas Corp

($MM)

	DCF Capital Structure	Year End, 2006	Year End, 2005	Year End, 2004	Year End, 2003	Year End, 2002	Notes
MARKET VALUE OF COMMON EQUITY							
Book Value, Common Shareholder's Equity	$901	$901	$751	$706	$630	$596	[a]
Shares Outstanding (in millions) - Common	42	42	39	37	34	33	[b]
Price per Share - Common	$39	$39	$27	$25	$23	$23	[c]
Market Value of Common Equity	$1,626	$1,613	$1,042	$938	$784	$770	[d] = [b] x [c].
Market to Book Value of Common Equity	1.80	1.79	1.39	1.33	1.24	1.29	[e] = [d] / [a].
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	[f]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	[g] = [f].
MARKET VALUE OF DEBT							
Current Assets	$502	$502	$543	$432	$281	$262	[h]
Current Liabilities	$496	$496	$621	$483	$310	$313	[i]
Current Portion of Long-Term Debt	$28	$28	$83	$30	$6	$9	[j]
Net Working Capital	$33	$33	$5	($21)	($23)	($43)	[k] = [h] - ([i] - [j]).
Notes Payable (Short-Term Debt)	$24	$24	$24	$100	$52	$53	[l]
Adjusted Short-Term Debt	$0	$0	$0	$21	$23	$43	[m] = See Sources and Notes.
Long-Term Debt	$1,386	$1,386	$1,325	$1,263	$1,221	$1,152	[n]
Book Value of Long-Term Debt	$1,414	$1,414	$1,408	$1,314	$1,250	$1,204	[o] = [n] + [j] + [m].
Adjustment to Book Value of Long-Term Debt	$80	$80	$145	$154	$126	$66	[p] = See Sources and Notes.
Market Value of Long-Term Debt	$1,494	$1,494	$1,553	$1,468	$1,377	$1,269	[q] = [p] + [o].
Market Value of Debt	$1,494	$1,494	$1,553	$1,468	$1,377	$1,269	[r] = [q].
MARKET VALUE OF FIRM							
	$3,121	$3,107	$2,596	$2,406	$2,160	$2,039	[s] = [d] + [g] + [r].
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	52.12%	51.91%	40.16%	38.97%	36.28%	37.77%	[t] = [d] / [s].
Preferred Equity - Market Value Ratio	-	-	-	-	-	-	[u] = [g] / [s].
Debt - Market Value Ratio	47.88%	48.09%	59.84%	61.03%	63.72%	62.23%	[v] = [r] / [s].

Sources and Notes:

Bloomberg as of April 09, 2007

Capital structure from Year End, 2006 calculated using respective balance sheet information and 5-day average prices ending at period end.

The DCF Capital structure is calculated using 4th Quarter, 2006 balance sheet information and a 15-trading day average closing price ending on 4/9/2007.

Prices are reported in Workpaper #1 to Table No. MJV-6.

[m] =

(1): 0 if [k] > 0.

(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].

(3): [l] if [k] < 0 and |[k]| > [l].

[p]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2006 10-K.

Table No. MJV-3

Market Value of the MJV US Gas LDC Sample

Panel G: WGL Holdings Inc

($MM)

	DCF Capital Structure	Year End, 2006	Year End, 2005	Year End, 2004	Year End, 2003	Year End, 2002	Notes
MARKET VALUE OF COMMON EQUITY							
Book Value, Common Shareholder's Equity	$922	$922	$894	$853	$818	$766	[a]
Shares Outstanding (in millions) - Common	49	49	49	49	49	49	[b]
Price per Share - Common	$32	$33	$30	$31	$28	$24	[c]
Market Value of Common Equity	$1,573	$1,603	$1,470	$1,509	$1,366	$1,166	[d] = [b] x [c].
Market to Book Value of Common Equity	1.71	1.74	1.64	1.77	1.67	1.52	[e] = [d] / [a].
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	$28	$28	$28	$28	$28	$28	[f]
Market Value of Preferred Equity	$28	$28	$28	$28	$28	$28	[g] = [f].
MARKET VALUE OF DEBT							
Current Assets	$562	$562	$481	$433	$409	$341	[h]
Current Liabilities	$561	$561	$412	$413	$386	$338	[i]
Current Portion of Long-Term Debt	$61	$61	$50	$61	$12	$42	[j]
Net Working Capital	$62	$62	$120	$81	$35	$46	[k] = [h] - ([i] - [j]).
Notes Payable (Short-Term Debt)	$177	$177	$41	$96	$167	$91	[l]
Adjusted Short-Term Debt	$0	$0	$0	$0	$0	$0	[m] = See Sources and Notes.
Long-Term Debt	$576	$576	$584	$590	$637	$668	[n]
Book Value of Long-Term Debt	$637	$637	$634	$651	$649	$710	[o] = [n] + [j] − [m].
Adjustment to Book Value of Long-Term Debt	$17	$17	$43	$56	$86	$58	[p] = See Sources and Notes.
Market Value of Long-Term Debt	$654	$654	$677	$707	$735	$768	[q] = [p] + [o].
Market Value of Debt	$654	$654	$677	$707	$735	$768	[r] = [q].
MARKET VALUE OF FIRM							
	$2,256	$2,285	$2,175	$2,244	$2,128	$1,962	[s] = [d] + [g] + [r].
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	69.75%	70.14%	67.58%	67.23%	64.16%	59.43%	[t] = [d] / [s].
Preferred Equity - Market Value Ratio	1.25%	1.23%	1.30%	1.26%	1.32%	1.44%	[u] = [g] / [s].
Debt - Market Value Ratio	29.00%	28.63%	31.12%	31.52%	34.52%	39.13%	[v] = [r] / [s].

Sources and Notes:
Bloomberg as of April 09, 2007
Capital structure from Year End, 2006 calculated using respective balance sheet information and 5-day average prices ending at period end.
The DCF Capital structure is calculated using 4th Quarter, 2006 balance sheet information and a 15-trading day average closing price ending on 4/9/2007.
Prices are reported in Workpaper #1 to Table No. MJV-6.
[m] =
(1): 0 if [k] > 0.
(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].
(3): [l] if [k] < 0 and |[k]| > [l].
[p]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2006 10-K.

Table No. MJV-3

Market Value of the MJV US Gas LDC Sample

Panel H: AGL Resources Inc

($MM)

	DCF Capital Structure	Year End, 2006	Year End, 2005	Year End, 2004	Year End, 2003	Year End, 2002	Notes
MARKET VALUE OF COMMON EQUITY							
Book Value, Common Shareholder's Equity	$1,609	$1,609	$1,499	$1,385	$945	$710	[a]
Shares Outstanding (in millions) - Common	78	78	78	77	65	57	[b]
Price per Share - Common	$43	$39	$35	$33	$29	$24	[c]
Market Value of Common Equity	$3,310	$3,042	$2,708	$2,546	$1,879	$1,381	[d] = [b] x [c].
Market to Book Value of Common Equity	2.06	1.89	1.81	1.84	1.99	1.94	[e] = [d] / [a].
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$227	[f]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$227	[g] = [f].
MARKET VALUE OF DEBT							
Current Assets	$1,822	$1,822	$2,041	$1,457	$742	$586	[h]
Current Liabilities	$1,627	$1,627	$1,968	$1,477	$1,048	$1,016	[i]
Current Portion of Long-Term Debt	$0	$0	$0	$0	$77	$30	[j]
Net Working Capital	$195	$195	$73	($20)	($229)	($399)	[k] = [h] - ([i] - [j]).
Notes Payable (Short-Term Debt)	$539	$539	$522	$334	$306	$389	[l]
Adjusted Short-Term Debt	$0	$0	$0	$20	$229	$389	[m] = See Sources and Notes.
Long-Term Debt	$1,622	$1,622	$1,615	$1,623	$956	$767	[n]
Book Value of Long-Term Debt	$1,622	$1,622	$1,615	$1,643	$1,262	$1,186	[o] = [n] + [j] + [m].
Adjustment to Book Value of Long-Term Debt	$83	$83	$169	$193	$133	$87	[p] = See Sources and Notes
Market Value of Long-Term Debt	$1,705	$1,705	$1,784	$1,836	$1,395	$1,273	[q] = [p] + [o]
Market Value of Debt	$1,705	$1,705	$1,784	$1,836	$1,395	$1,273	[r] = [q].
MARKET VALUE OF FIRM							
	$5,015	$4,747	$4,492	$4,382	$3,274	$2,881	[s] = [d] + [g] + [r].
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	66.00%	64.09%	60.29%	58.10%	57.39%	47.93%	[t] = [d] / [s].
Preferred Equity - Market Value Ratio	-	-	-	-	-	7.89%	[u] = [g] / [s].
Debt - Market Value Ratio	34.00%	35.91%	39.71%	41.90%	42.61%	44.18%	[v] = [r] / [s].

Sources and Notes:

Bloomberg as of April 09, 2007

Capital structure from Year End, 2006 calculated using respective balance sheet information and 5-day average prices ending at period end.

The DCF Capital structure is calculated using 4th Quarter, 2006 balance sheet information and a 15-trading day average closing price ending on 4/9/2007.
Prices are reported in Workpaper #1 to Table No. MJV-6.

[m] =

(1): 0 if [k] > 0.

(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].

(3): [l] if [k] < 0 and |[k]| > [l].

[p]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2006 10-K.

Table No. MJV-3

Market Value of the MJV US Gas LDC Sample

Panel I: Vectren Corp

($MM)

	DCF Capital Structure	Year End, 2006	Year End, 2005	Year End, 2004	Year End, 2003	Year End, 2002	Notes
MARKET VALUE OF COMMON EQUITY							
Book Value, Common Shareholder's Equity	$1,174	$1,174	$1,143	$1,095	$1,072	$870	[a]
Shares Outstanding (in millions) - Common	76	76	76	76	76	68	[b]
Price per Share - Common	$28	$28	$27	$27	$25	$23	[c]
Market Value of Common Equity	$2,168	$2,156	$2,063	$2,040	$1,859	$1,548	[d] = [b] x [c].
Market to Book Value of Common Equity	1.85	1.84	1.80	1.86	1.73	1.78	[e] = [d] / [a].
MARKET VALUE OF PREFERRED EQUITY							
Book Value of Preferred Equity	$0	$0	$0	$0	$0	$0	[f]
Market Value of Preferred Equity	$0	$0	$0	$0	$0	$0	[g] = [f].
MARKET VALUE OF DEBT							
Current Assets	$716	$716	$725	$586	$512	$465	[h]
Current Liabilities	$961	$961	$840	$826	$584	$774	[i]
Current Portion of Long-Term Debt	$44	$44	$54	$49	$29	$66	[j]
Net Working Capital	($201)	($201)	($60)	($191)	($44)	($242)	[k] = [h] - ([i] - [j]).
Notes Payable (Short-Term Debt)	$465	$465	$300	$412	$275	$400	[l]
Adjusted Short-Term Debt	$201	$201	$60	$191	$44	$242	[m] = See Sources and Notes.
Long-Term Debt	$1,208	$1,208	$1,198	$1,017	$1,073	$954	[n]
Book Value of Long-Term Debt	$1,454	$1,454	$1,312	$1,256	$1,145	$1,263	[o] = [n] + [j] + [m].
Adjustment to Book Value of Long-Term Debt	$20	$20	$56	$76	$78	$70	[p] = See Sources and Notes.
Market Value of Long-Term Debt	$1,473	$1,473	$1,368	$1,332	$1,223	$1,333	[q] = [p] + [o].
Market Value of Debt	$1,473	$1,473	$1,368	$1,332	$1,223	$1,333	[r] = [q].
MARKET VALUE OF FIRM	$3,641	$3,629	$3,431	$3,373	$3,082	$2,882	[s] = [d] + [g] + [r].
DEBT AND EQUITY TO MARKET VALUE RATIOS							
Common Equity - Market Value Ratio	59.54%	59.40%	60.12%	60.49%	60.30%	53.73%	[t] = [d] / [s].
Preferred Equity - Market Value Ratio	-	-	-	0.00%	0.01%	0.01%	[u] = [g] / [s].
Debt - Market Value Ratio	40.46%	40.60%	39.88%	39.51%	39.69%	46.26%	[v] = [r] / [s].

Sources and Notes:

Bloomberg as of April 09, 2007

Capital structure from Year End, 2006 calculated using respective balance sheet information and 5-day average prices ending at period end.

The DCF Capital structure is calculated using 4th Quarter, 2006 balance sheet information and a 15-trading day average closing price ending on 4/9/2007.

Prices are reported in Workpaper #1 to Table No. MJV-6.

[m] =

(1): 0 if [k] > 0.

(2): The absolute value of [k] if [k] < 0 and |[k]| < [l].

(3): [l] if [k] < 0 and |[k]| > [l].

[p]: Difference between fair value of Long-Term debt and carrying amount of Long-Term debt per company 10-K. Data for adjustment is from 2006 10-K.

Table No. MJV-4

MJV US Gas LDC Sample

Capital Structure Summary

Company		DCF Capital Structure			5-Year Average Capital Structure		
		Common Equity - Value Ratio [1]	Preferred Equity - Value Ratio [2]	Debt - Value Ratio [3]	Common Equity - Value Ratio [4]	Preferred Equity - Value Ratio [5]	Debt - Value Ratio [6]
Atmos Energy Corp		0.56	-	0.44	0.56	-	0.44
Laclede Group Inc/The	*	0.62	0.00	0.38	0.59	0.00	0.41
Northwest Natural Gas Co	*	0.68	-	0.32	0.61	0.00	0.39
Piedmont Natural Gas Co	*	0.69	-	0.31	0.68	-	0.32
South Jersey Industries Inc		0.72	-	0.28	0.63	0.00	0.37
Southwest Gas Corp		0.52	-	0.48	0.41	-	0.59
WGL Holdings Inc	*	0.70	0.01	0.29	0.66	0.01	0.33
AGL Resources Inc		0.66	-	0.34	0.58	0.02	0.41
Vectren Corp		0.60	-	0.40	0.59	0.00	0.41
Average		0.64	0.00	0.36	0.59	0.00	0.41
Subsample Average		0.67	0.00	0.33	0.63	0.00	0.36

Sources and Notes:
[1], [4]:Workpaper #1 to Table No. MJV-4.
[2], [5]:Workpaper #2 to Table No. MJV-4.
[3], [6]:Workpaper #3 to Table No. MJV-4.
Values in this table may not add up exactly to 1.0 because of rounding.

*Represents companies in the subsample.

Table No. MJV-5

MJV US Gas LDC Sample

Combined Bloomberg Estimated and Value Line Estimated Growth Rates

Company	Bloomberg Estimate		Value Line			
	BEst Long-Term Growth Rate	Number of Estimates	EPS Year 2008 Estimate	EPS Year 2010 - 2012 Estimate	Annualized Growth Rate	Combined BEst and Value Line Growth Rate
	[1]	[2]	[3]	[4]	[5]	[6]
Atmos Energy Corp	5.8%	4	$2.10	$2.50	6.0%	5.8%
Laclede Group Inc/The	3.0%	1	$2.00	$2.35	5.5%	4.3%
Northwest Natural Gas Co	4.8%	3	$2.55	$2.95	5.0%	4.9%
Piedmont Natural Gas Co	5.0%	2	$1.45	$1.55	2.2%	4.1%
South Jersey Industries Inc	6.3%	3	$2.90	$3.30	4.4%	5.9%
Southwest Gas Corp	5.5%	2	$2.25	$2.60	4.9%	5.3%
WGL Holdings Inc	3.7%	3	$2.05	$2.20	2.4%	3.3%
AGL Resources Inc	4.5%	3	$2.90	$3.10	2.2%	3.9%
Vectren Corp	2.2%	1	$1.90	$2.00	1.7%	2.0%

Sources and Notes:

[1] - [2]: Bloomberg as of April 09, 2007.

[3] - [4]: Most recent Value Line Standard Edition dated as of March 16, 2007, except for Vectren which is as of March 30, 2007..

[5]: ([4] / [3]) ^ (1/3) - 1.

[6]: ([1] x [2] + [5]) / ([2] + 1).

Table No. MJV-6

DCF Cost of Equity of the MJV US Gas LDC Sample

Panel A: Simple DCF Method (Quarterly)

Company	Stock Price [1]	Quarterly Dividend Q4, 2006 [2]	Combined BEst and Value Line Long-Term Growth Rate [3]	Quarterly Growth Rate [4]	DCF Cost of Equity [5]
Atmos Energy Corp	$31.61	$0.32	5.8%	1.4%	10.1%
Laclede Group Inc/The	$31.18	$0.37	4.3%	1.0%	9.2%
Northwest Natural Gas Co	$45.94	$0.36	4.9%	1.2%	8.1%
Piedmont Natural Gas Co	$26.72	$0.24	4.1%	1.0%	7.9%
South Jersey Industries Inc	$38.06	$0.25	5.9%	1.4%	8.6%
Southwest Gas Corp	$38.94	$0.21	5.3%	1.3%	7.5%
WGL Holdings Inc	$32.19	$0.34	3.3%	0.8%	7.7%
AGL Resources Inc	$42.60	$0.37	3.9%	1.0%	7.6%
Vectren Corp	$28.49	$0.32	2.0%	0.5%	6.5%

Sources and Notes:

[1]: Workpaper #1 to Table No. MJV-6.

[2]: Workpaper #2 to Table No. MJV-6.

[3]: Table No. MJV-5, [6].

[4]: {(1 + [3]) ^ (1/4)} - 1.

[5]: {(([2] / [1]) x (1 + [4]) + [4] + 1) ^ 4} - 1.

Table No. MJV-6

DCF Cost of Equity of the MJV US Gas LDC Sample

Panel B: Multi-Stage DCF (Using Blue Chip Long-Term GDP Growth Forecast as the Perpetual Rate)

Company	Stock Price [1]	Quarterly Dividend Q4, 2006 [2]	Combined BEst and *Value Line* Long-Term Growth Rate [3]	Growth Rate: FY 2012 [4]	Growth Rate: FY 2013 [5]	Growth Rate: FY 2014 [6]	Growth Rate: FY 2015 [7]	Growth Rate: FY 2016 [8]	GDP Long-Term Growth Rate [9]	DCF Cost of Equity [10]
Atmos Energy Corp	$31.61	$0.32	5.8%	5.7%	5.6%	5.4%	5.3%	5.2%	5.1%	9.6%
Laclede Group Inc/The	$31.18	$0.37	4.3%	4.4%	4.5%	4.7%	4.8%	5.0%	5.1%	9.8%
Northwest Natural Gas Co	$45.94	$0.36	4.9%	4.9%	4.9%	5.0%	5.0%	5.1%	5.1%	8.3%
Piedmont Natural Gas Co	$26.72	$0.24	4.1%	4.3%	4.4%	4.6%	4.8%	4.9%	5.1%	8.7%
South Jersey Industries Inc	$38.06	$0.25	5.9%	5.7%	5.6%	5.5%	5.4%	5.2%	5.1%	8.0%
Southwest Gas Corp	$38.94	$0.21	5.3%	5.3%	5.2%	5.2%	5.2%	5.1%	5.1%	7.4%
WGL Holdings Inc	$32.19	$0.34	3.3%	3.6%	3.9%	4.2%	4.5%	4.8%	5.1%	9.1%
AGL Resources Inc	$42.60	$0.37	3.9%	4.1%	4.3%	4.5%	4.7%	4.9%	5.1%	8.5%
Vectren Corp	$28.49	$0.32	2.0%	2.5%	3.0%	3.5%	4.1%	4.6%	5.1%	8.9%

Sources and Notes:

[1]: Workpaper #1 to Table No. MJV-6.

[2]: Workpaper #2 to Table No. MJV-6.

[3]: Table No. MJV-5, [6].

[4]: [3] - {([3] - [9])/ 6}.

[5]: [4] - {([3] - [9])/ 6}.

[6]: [5] - {([3] - [9])/ 6}.

[7]: [6] - {([3] - [9])/ 6}.

[8]: [7] - {([3] - [9])/ 6}.

[9]: Blue Chip Economic Indicators published March 10, 2007. This number is assumed to be the perpetual growth rate. (See Appendix E).

[10]: Workpaper #3 to Table No. MJV-6.

Table No. MJV-7

Overall Cost of Capital of the MJV US Gas LDC Sample

Panel A: Simple DCF Method (Quarterly)

Company		4th Quarter, 2006 Bond Rating [1]	4th Quarter, 2006 Preferred Equity Rating [2]	DCF Cost of Equity [3]	DCF Common Equity to Market Value Ratio [4]	Cost of Preferred Equity [5]	DCF Preferred Equity to Market Value Ratio [6]	DCF Cost of Debt [7]	DCF Debt to Market Value Ratio [8]	Northwestern's Income Tax Rate [9]	Overall After- Tax Cost of Capital [10]
Atmos Energy Corp		BBB	-	10.1%	0.56	-	-	6.1%	0.44	35.0%	7.4%
Laclede Group Inc/The	*	A	A	9.2%	0.62	5.9%	0.00	5.9%	0.38	35.0%	7.1%
Northwest Natural Gas Co	*	AA	-	8.1%	0.68	-	-	5.7%	0.32	35.0%	6.7%
Piedmont Natural Gas Co	*	A	-	7.9%	0.69	-	-	5.9%	0.31	35.0%	6.6%
South Jersey Industries Inc		BBB	-	8.6%	0.72	-	-	6.1%	0.28	35.0%	7.3%
Southwest Gas Corp		BBB	-	7.5%	0.52	-	-	6.1%	0.48	35.0%	5.8%
WGL Holdings Inc	*	AA	AA	7.7%	0.70	5.8%	0.01	5.7%	0.29	35.0%	6.6%
AGL Resources Inc		A	-	7.6%	0.66	-	-	5.9%	0.34	35.0%	6.3%
Vectren Corp		A	-	6.5%	0.60	-	-	5.9%	0.40	35.0%	5.4%
Average				8.2%	0.64	5.8%	0.00	5.9%	0.36	35.0%	6.6%
Subsample Average				8.2%	0.67	5.8%	0.00	5.8%	0.33	35.0%	6.8%

Sources and Notes:
[1]: Bloomberg as of April 09, 2007.
[2]: Preferred ratings were assumed equal to debt ratings.
[3]: Table No. MJV-6; Panel A, [5].
[4]: Table No. MJV-4, [1].
[5]: Workpaper #2 to Table No. MJV-11, Panel B, [6].
[6]: Table No. MJV-4, [2].
[7]: Workpaper #2 toTable No. MJV-11, Panel A, [6].
[8]: Table No. MJV-4, [3].
[9]: Provided by Northwestern.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}.

*Represents companies in the subsample.

Table No. MJV-7

Overall Cost of Capital of the MJV US Gas LDC Sample

Panel B: Multi-Stage DCF (Using Blue Chip Long-Term GDP Growth Forecast as the Perpetual Rate)

Company		4th Quarter, 2006 Bond Rating [1]	4th Quarter, 2006 Preferred Equity Rating [2]	DCF Cost of Equity [3]	DCF Common Equity to Market Value Ratio [4]	Cost of Preferred Equity [5]	DCF Preferred Equity to Market Value Ratio [6]	DCF Cost of Debt [7]	DCF Debt to Market Value Ratio [8]	Northwestern's Income Tax Rate [9]	Overall After-Tax Cost of Capital [10]
Atmos Energy Corp		BBB	-	9.6%	0.56	-	-	6.1%	0.44	35.0%	7.1%
Laclede Group Inc/The	*	A	A	9.8%	0.62	5.9%	0.00	5.9%	0.38	35.0%	7.5%
Northwest Natural Gas Co	*	AA	-	8.3%	0.68	-	-	5.7%	0.32	35.0%	6.8%
Piedmont Natural Gas Co	*	A	-	8.7%	0.69	-	-	5.9%	0.31	35.0%	7.1%
South Jersey Industries Inc		BBB	-	8.0%	0.72	-	-	6.1%	0.28	35.0%	6.8%
Southwest Gas Corp		BBB	-	7.4%	0.52	-	-	6.1%	0.48	35.0%	5.7%
WGL Holdings Inc	*	AA	AA	9.1%	0.70	5.8%	0.01	5.7%	0.29	35.0%	7.5%
AGL Resources Inc		A	-	8.5%	0.66	-	-	5.9%	0.34	35.0%	6.9%
Vectren Corp		A	-	8.9%	0.60	-	-	5.9%	0.40	35.0%	6.9%
Average				8.7%	0.64	5.8%	0.00	5.9%	0.36	35.0%	6.9%
Subsample Average				9.0%	0.67	5.8%	0.00	5.8%	0.33	35.0%	7.2%

Sources and Notes:

[1]: Bloomberg as of April 09, 2007.
[2]: Preferred ratings were assumed equal to debt ratings.
[3]: Table No. MJV-6, Panel B, [10].
[4]: Table No. MJV-4, [1].
[5]: Workpaper #2 to Table No. MJV-11, Panel B, [6].
[6]: Table No. MJV-4, [2].
[7]: Workpaper #2 toTable No. MJV-11, Panel A, [6].
[8]: Table No. MJV-4, [3].
[9]: Provided by Northwestern.
[10]: ([3] x [4]) + ([5] x [6]) + {[7] x [8] x (1 - [9])}.

*Represents companies in the subsample.

Table No. MJV-8

DCF Cost of Equity at Northwestern Capital Structure

MJV US Gas LDC Sample

Panel A: Using Value Line Betas

	Overall Cost of Capital [1]	Northwestern's Regulatory % Debt [2]	Northwestern's Cost of Debt [3]	Northwestern's Income Tax Rate [4]	Northwestern's Regulatory % Equity [5]	Estimated Return on Equity [6]
Using All Companies with Bloomberg Forecast						
Simple DCF Quarterly	6.6%	0.49	6.1%	35.0%	0.51	9.1%
Multi-Stage DCF - Using the Blue Chip Economic Indicator Long-Term GDP as the Perpetual Rate	6.9%	0.49	6.1%	35.0%	0.51	9.7%

Sources and Notes:
[1]: Table No. MJV-7; Panels A-B, [10].
[2]: Provided by Northwestern.
[3]: Based off an BBB rating, as provided by Northwestern. Yield pulled from Bloomberg as of March 27, 2007.
[4]: Provided by Northwestern.
[5]: Provided by Northwestern.
[6]: {[1] - ([2] x [3] x (1 - [4]))} / [5].

Table No. MJV-8

DCF Cost of Equity at Northwestern Capital Structure

MJV US Gas LDC Sample

Panel B: Using Subsample and Value Line Betas

	Overall Cost of Capital [1]	Northwestern's Regulatory % Debt [2]	Northwestern's Cost of Debt [3]	Northwestern's Income Tax Rate [4]	Northwestern's Regulatory % Equity [5]	Estimated Return on Equity [6]
Using All Companies with Bloomberg Forecast						
Simple DCF Quarterly	6.8%	0.49	6.1%	35.0%	0.51	9.4%
Multi-Stage DCF - Using the Blue Chip Economic Indicator Long-Term GDP as the Perpetual Rate	7.2%	0.49	6.1%	35.0%	0.51	10.3%

Sources and Notes:
[1]: Table No. MJV-7; Panels A-B, [10].
[2]: Provided by Northwestern.
[3]: Based off an BBB rating, as provided by Northwestern. Yield pulled from Bloomberg as of March 27, 2007.
[4]: Provided by Northwestern.
[5]: Provided by Northwestern.
[6]: {[1] - ([2] x [3] x (1 - [4]))} / [5].

Table No. MJV-9 - Interest Rate Forecasts

MJV US Gas LDC Sample

Panel A: US Interest Rate Series (All Constant Maturity Series)

	Trading Date	30 Day	90 Day	180 Day	1 Year	2 Year	3 Year	5 Year	7 Year	10 Year	Long Term
	3/20/2007	5.22%	5.06%	5.12%	4.94%	4.60%	4.51%	4.47%	4.49%	4.56%	4.79%
	3/21/2007	5.24%	5.05%	5.08%	4.89%	4.51%	4.44%	4.43%	4.45%	4.53%	4.78%
	3/22/2007	5.23%	5.06%	5.08%	4.91%	4.58%	4.51%	4.49%	4.52%	4.60%	4.86%
	3/23/2007	5.24%	5.08%	5.10%	4.93%	4.60%	4.54%	4.52%	4.54%	4.62%	4.88%
	3/26/2007	5.22%	5.06%	5.09%	4.91%	4.56%	4.50%	4.48%	4.51%	4.60%	4.86%
	3/27/2007	5.20%	5.08%	5.09%	4.91%	4.58%	4.51%	4.50%	4.53%	4.62%	4.89%
	3/28/2007	5.18%	5.06%	5.08%	4.90%	4.53%	4.49%	4.50%	4.53%	4.62%	4.90%
	3/29/2007	5.05%	5.05%	5.06%	4.90%	4.58%	4.52%	4.53%	4.55%	4.64%	4.90%
	3/30/2007	5.07%	5.04%	5.06%	4.90%	4.58%	4.54%	4.54%	4.58%	4.65%	4.92%
	4/2/2007	5.12%	5.04%	5.09%	4.92%	4.60%	4.53%	4.54%	4.57%	4.65%	4.92%
	4/3/2007	5.15%	5.05%	5.09%	4.93%	4.63%	4.57%	4.56%	4.59%	4.67%	4.93%
	4/4/2007	5.16%	5.07%	5.08%	4.92%	4.61%	4.55%	4.55%	4.58%	4.66%	4.92%
	4/5/2007	5.10%	5.04%	5.07%	4.93%	4.63%	4.57%	4.57%	4.60%	4.68%	4.95%
	4/6/2007	5.10%	5.05%	5.10%	4.98%	4.75%	4.68%	4.67%	4.69%	4.76%	5.00%
	4/9/2007	5.08%	5.02%	5.11%	4.98%	4.73%	4.67%	4.66%	4.68%	4.75%	5.00%
[A]	Average:	5.16%	5.05%	5.09%	4.92%	4.60%	4.54%	4.53%	4.56%	4.64%	4.90%
[B]	Maturity Premium:	0.00%	0.10%	0.20%	0.33%	0.59%	0.75%	1.00%	1.15%	1.27%	1.50%
[C]	Implied Short-Term Yield:	5.16%	4.95%	4.89%	4.59%	4.01%	3.79%	3.53%	3.41%	3.37%	3.40%

Sources and Notes:

[A]: Average over the last 15 trading days.

[B]: Workpaper #1 to Table No. MJV-9, Panel C, [2].

[C]: [A] - [B].

St. Louis Federal Reserve Bank. {http://research.stlouisfed.org/fred2/}. The most recent 15 trading days are used.

Table No. MJV-9 - Interest Rate Forecasts

MJV US Gas LDC Sample

Panel B: Forecasted Short-Term Interest Rates

	30 Day [1]	90 Day [2]	180 Day [3]	1 Year [4]	2 Year [5]	3 Year [6]	5 Year [7]	7 Year [8]	10 Year [9]	Total Days [10]	Implicit Short-Term Rate [11]
[A] Implied Short-Term Yield:	5.16%	4.95%	4.89%	4.59%	4.01%	3.79%	3.53%	3.41%	3.37%		
[B] Days Remaining in 2007	30	60	90	86						266	4.84%
[C] Days Remaining in 2008				99	266					365	4.17%
[D] Days Remaining in 2009					99	266				365	3.85%
[E] Days Remaining in 2010						99	266			365	3.60%
[F] Days Remaining in 2011							99	266		365	3.44%
[G] Days Remaining in 2012								99	266	99	13.04%
[H] Total Days	30	60	90	185	365	365	730	730	798	1825	
[I] Implicit Short-Term Rate for 2008-2011										1460	3.77%
[J] Implicit Short-Term Rate for 2008-2012										1559	4.33%

Sources and Notes:

[A]: Table No. MJV-9 - Interest Rate Forecasts Panel A, [C].

[B] - [G]: Total number of days remaining for each period, beginning with March 20, 2007.

[H]: Sum of [B] through [G] for the respective period.

[11]: [(1+ Implied Short-Term Yield$_1$)^(days remaining in period$_1$)x…x(1+Implied Short-Term Yield$_n$)^(days remaining in period$_n$)]^(1/[9])-1.

This formula is applied to all periods from 1 to n in each year.

[I]: ((1+[10][C])^[9][C]x…x(1+10[F])^[9][F]))^(1/[9][I])-1.

[J]: ((1+[10][C])^[9][C]x…x(1+10[G])^[9][G]))^(1/[9][J])-1.

Table No. MJV-10

Risk Positioning Cost of Equity of the MJV US Gas LDC Sample

Using Value Line Betas and the Long-Term Risk-Free Rate

Company	US Long-Term Risk-Free Rate [1]	Value Line Betas [2]	Long-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (0.5%) Cost of Equity [5]	ECAPM (1.5%) Cost of Equity [6]
Atmos Energy Corp	4.9%	0.80	6.50%	10.1%	10.2%	10.4%
Laclede Group Inc/The	4.9%	0.85	6.50%	10.4%	10.5%	10.7%
Northwest Natural Gas Co	4.9%	0.75	6.50%	9.8%	9.9%	10.2%
Piedmont Natural Gas Co	4.9%	0.80	6.50%	10.1%	10.2%	10.4%
South Jersey Industries Inc	4.9%	0.70	6.50%	9.5%	9.6%	9.9%
Southwest Gas Corp	4.9%	0.85	6.50%	10.4%	10.5%	10.7%
WGL Holdings Inc	4.9%	0.85	6.50%	10.4%	10.5%	10.7%
AGL Resources Inc	4.9%	0.95	6.50%	11.1%	11.1%	11.2%
Vectren Corp	4.9%	0.95	6.50%	11.1%	11.1%	11.2%

Sources and Notes:

[1]: Table No. MJV-9 - Interest Rate Forecasts, Panel A, Row [A].

[2]: Workpaper # 1 to Table No. MJV-10, column [1].

[3]: Vilbert Written Evidence, Appendix B.

[4]: [1] + ([2] x [3]).

[5]: ([1] + 0.5%) + [2] x ([3] - 0.5%).

[6]: ([1] + 1.5%) + [2] x ([3] - 1.5%).

Table No. MJV-10

Risk Positioning Cost of Equity of the MJV US Gas LDC Sample

Panel B: Using Value Line Betas and the Short-Term Risk-Free Rate.

Company	US Short-Term Risk-Free Rate [1]	Value Line Betas [2]	Short-Term Market Risk Premium [3]	CAPM Cost of Equity [4]	ECAPM (1%) Cost of Equity [5]	ECAPM (2%) Cost of Equity [6]	ECAPM (3%) Cost of Equity [7]
Atmos Energy Corp	3.8%	0.80	8.0%	10.2%	10.4%	10.6%	10.8%
Laclede Group Inc/The	3.8%	0.85	8.0%	10.6%	10.8%	10.9%	11.1%
Northwest Natural Gas Co	3.8%	0.75	8.0%	9.8%	10.1%	10.3%	10.6%
Piedmont Natural Gas Co	3.8%	0.80	8.0%	10.2%	10.4%	10.6%	10.8%
South Jersey Industries Inc	3.8%	0.70	8.0%	9.4%	9.7%	10.0%	10.3%
Southwest Gas Corp	3.8%	0.85	8.0%	10.6%	10.8%	10.9%	11.1%
WGL Holdings Inc	3.8%	0.85	8.0%	10.6%	10.8%	10.9%	11.1%
AGL Resources Inc	3.8%	0.95	8.0%	11.4%	11.5%	11.5%	11.6%
Vectren Corp	3.8%	0.95	8.0%	11.4%	11.5%	11.5%	11.6%

Sources and Notes:
[1]: Table No. MJV-9 - Interest Rate Forecasts, Panel B, Row [I].
[2]: Workpaper # 1 to Table No. MJV-10, column [1].
[3]: Vilbert Written Evidence, Appendix B.
[4]: [1] + ([2] x [3]).
[5]: ([1] + 1%) + [2] x ([3] - 1%).
[6]: ([1] + 2%) + [2] x ([3] - 2%).
[7]: ([1] + 3%) + [2] x ([3] - 3%).

Table No. MJV-11

Overall Cost of Capital of the MJV US Gas LDC Sample

Panel A: CAPM Cost of Equity Based on Value Line Betas and a Long-Term Risk-Free Rate

Company		CAPM Cost of Equity [1]	5-Year Average Common Equity to Market Value Ratio [2]	Weighted - Average Cost of Preferred Equity [3]	5-Year Average Preferred Equity to Market Value Ratio [4]	Weighted Average Cost of Debt [5]	5-Year Average Debt to Market Value Ratio [6]	Northwestern's Income Tax Rate [7]	Overall After- Tax Cost of Capital [8]
Atmos Energy Corp		10.1%	0.56	-	-	6.0%	0.44	35.0%	7.4%
Laclede Group Inc/The	*	10.4%	0.59	5.9%	0.00	5.9%	0.41	35.0%	7.7%
Northwest Natural Gas Co	*	9.8%	0.61	5.8%	0.00	5.8%	0.39	35.0%	7.4%
Piedmont Natural Gas Co	*	10.1%	0.68	-	-	5.9%	0.32	35.0%	8.1%
South Jersey Industries Inc		9.5%	0.63	6.0%	0.00	6.1%	0.37	35.0%	7.4%
Southwest Gas Corp		10.4%	0.41	-	-	6.1%	0.59	35.0%	6.6%
WGL Holdings Inc	*	10.4%	0.66	5.8%	0.01	5.7%	0.33	35.0%	8.2%
AGL Resources Inc		11.1%	0.58	5.9%	0.02	5.9%	0.41	35.0%	8.0%
Vectren Corp		11.1%	0.59	5.9%	0.00	5.9%	0.41	35.0%	8.1%
Average		10.3%	0.59	5.9%	0.00	5.9%	0.41	35.0%	7.7%
Subsample Average		10.2%	0.63	5.8%	0.00	5.8%	0.36	35.0%	7.8%

Sources and Notes:

[1]: Table No. MJV-10; Panel A, [4].

[2]: Table No. MJV-4, [4].

[3]: Workpaper #2 to Table No. MJV-11 ; Panel B, [1].

[4]: Table No. MJV-4, [5].

[5]: Workpaper #2 to Table No. MJV-11 ; Panel A, [1].

[6]: Table No. MJV-4, [6].

[7]: Provided by Northwestern.

[8]: ([1] x [2]) + ([3] x [4]) + {[5] x [6] x (1 - [7])}.

*Represents companies in the subsample.

Table No. MJV-11

Overall Cost of Capital of the MJV US Gas LDC Sample

Panel B: ECAPM (0.5%) Cost of Equity Based on Value Line Betas and a Long-Term Risk-Free Rate

Company		ECAPM (0.5%) Cost of Equity [1]	5-Year Average Common Equity to Market Value Ratio [2]	Weighted - Average Cost of Preferred Equity [3]	5-Year Average Preferred Equity to Market Value Ratio [4]	Weighted Average Cost of Debt [5]	5-Year Average Debt to Market Value Ratio [6]	Northwestern's Income Tax Rate [7]	Overall After- Tax Cost of Capital [8]
Atmos Energy Corp		10.2%	0.56	-	-	6.0%	0.44	35.0%	7.4%
Laclede Group Inc/The	*	10.5%	0.59	5.9%	0.00	5.9%	0.41	35.0%	7.8%
Northwest Natural Gas Co	*	9.9%	0.61	5.8%	0.00	5.8%	0.39	35.0%	7.5%
Piedmont Natural Gas Co	*	10.2%	0.68	-	-	5.9%	0.32	35.0%	8.1%
South Jersey Industries Inc		9.6%	0.63	6.0%	0.00	6.1%	0.37	35.0%	7.5%
Southwest Gas Corp		10.5%	0.41	-	-	6.1%	0.59	35.0%	6.6%
WGL Holdings Inc	*	10.5%	0.66	5.8%	0.01	5.7%	0.33	35.0%	8.2%
AGL Resources Inc		11.1%	0.58	5.9%	0.02	5.9%	0.41	35.0%	8.0%
Vectren Corp		11.1%	0.59	5.9%	0.00	5.9%	0.41	35.0%	8.1%
Average		10.4%	0.59	5.9%	0.00	5.9%	0.41	35.0%	7.7%
Subsample Average		10.3%	0.63	5.8%	0.00	5.8%	0.36	35.0%	7.9%

Sources and Notes:
[1]: Table No. MJV-10; Panel A, [5].
[2]: Table No. MJV-4, [4].
[3]: Workpaper #2 to Table No. MJV-11 ; Panel B, [1].
[4]: Table No. MJV-4, [5].
[5]: Workpaper #2 to Table No. MJV-11 : Panel A, [1].
[6]: Table No. MJV-4, [6].
[7]: Provided by Northwestern.
[8]: ([1] x [2]) + ([3] x [4]) + {[5] x [6] x (1 - [7])}.

*Represents companies in the subsample.

Table No. MJV-11

Overall Cost of Capital of the MJV US Gas LDC Sample

Panel C: ECAPM (1.5%) Cost of Equity Based on Value Line Betas and a Long-Term Risk-Free Rate

Company		ECAPM (1.5%) Cost of Equity [1]	5-Year Average Common Equity to Market Value Ratio [2]	Weighted - Average Cost of Preferred Equity [3]	5-Year Average Preferred Equity to Market Value Ratio [4]	Weighted Average Cost of Debt [5]	5-Year Average Debt to Market Value Ratio [6]	Northwestern's Income Tax Rate [7]	Overall After- Tax Cost of Capital [8]
Atmos Energy Corp		10.4%	0.56	-	-	6.0%	0.44	35.0%	7.5%
Laclede Group Inc/The	*	10.7%	0.59	5.9%	0.00	5.9%	0.41	35.0%	7.8%
Northwest Natural Gas Co	*	10.2%	0.61	5.8%	0.00	5.8%	0.39	35.0%	7.7%
Piedmont Natural Gas Co	*	10.4%	0.68	-	-	5.9%	0.32	35.0%	8.3%
South Jersey Industries Inc		9.9%	0.63	6.0%	0.00	6.1%	0.37	35.0%	7.7%
Southwest Gas Corp		10.7%	0.41	-	-	6.1%	0.59	35.0%	6.7%
WGL Holdings Inc	*	10.7%	0.66	5.8%	0.01	5.7%	0.33	35.0%	8.3%
AGL Resources Inc		11.2%	0.58	5.9%	0.02	5.9%	0.41	35.0%	8.1%
Vectren Corp		11.2%	0.59	5.9%	0.00	5.9%	0.41	35.0%	8.1%
Average		10.6%	0.59	5.9%	0.00	5.9%	0.41	35.0%	7.8%
Subsample Average		10.5%	0.63	5.8%	0.00	5.8%	0.36	35.0%	8.0%

Sources and Notes:
[1]: Table No. MJV-10; Panel A, [6].
[2]: Table No. MJV-4, [4].
[3]: Workpaper #2 to Table No. MJV-11 ; Panel B, [1].
[4]: Table No. MJV-4, [5].
[5]: Workpaper #2 to Table No. MJV-11 : Panel A, [1].
[6]: Table No. MJV-4, [6].
[7]: Provided by Northwestern.
[8]: ([1] x [2]) + ([3] x [4]) + {[5] x [6] x (1 - [7])}.

*Represents companies in the subsample.

Table No. MJV-11

Overall Cost of Capital of the MJV US Gas LDC Sample

Panel D: CAPM Cost of Equity Based on Value Line Betas and a Short-Term Risk-Free Rate

Company		CAPM Cost of Equity [1]	5-Year Average Common Equity to Market Value Ratio [2]	Weighted - Average Cost of Preferred Equity [3]	5-Year Average Preferred Equity to Market Value Ratio [4]	Weighted Average Cost of Debt [5]	5-Year Average Debt to Market Value Ratio [6]	Northwestern's Income Tax Rate [7]	Overall After- Tax Cost of Capital [8]
Atmos Energy Corp		10.2%	0.56	-	-	6.0%	0.44	35.0%	7.4%
Laclede Group Inc/The	*	10.6%	0.59	5.9%	0.00	5.9%	0.41	35.0%	7.8%
Northwest Natural Gas Co	*	9.8%	0.61	5.8%	0.00	5.8%	0.39	35.0%	7.4%
Piedmont Natural Gas Co	*	10.2%	0.68	-	-	5.9%	0.32	35.0%	8.1%
South Jersey Industries Inc		9.4%	0.63	6.0%	0.00	6.1%	0.37	35.0%	7.4%
Southwest Gas Corp		10.6%	0.41	-	-	6.1%	0.59	35.0%	6.7%
WGL Holdings Inc	*	10.6%	0.66	5.8%	0.01	5.7%	0.33	35.0%	8.3%
AGL Resources Inc		11.4%	0.58	5.9%	0.02	5.9%	0.41	35.0%	8.2%
Vectren Corp		11.4%	0.59	5.9%	0.00	5.9%	0.41	35.0%	8.3%
Average		10.5%	0.59	5.9%	0.00	5.9%	0.41	35.0%	7.7%
Subsample Average		10.3%	0.63	5.8%	0.00	5.8%	0.36	35.0%	7.9%

Sources and Notes:
[1]: Table No. MJV-10; Panel B, [4].
[2]: Table No. MJV-4, [4].
[3]: Workpaper #2 to Table No. MJV-11 ; Panel B, [1].
[4]: Table No. MJV-4, [5].
[5]: Workpaper #2 to Table No. MJV-11 ; Panel A, [1].
[6]: Table No. MJV-4, [6].
[7]: Provided by Northwestern.
[8]: ([1] x [2]) + ([3] x [4]) + {[5] x [6] x (1 - [7])}.

*Represents companies in the subsample.

Table No. MJV-11

Overall Cost of Capital of the MJV US Gas LDC Sample

Panel E: ECAPM (1%) Cost of Equity Based on Value Line Betas and a Short-Term Risk-Free Rate

Company		ECAPM (1%) Cost of Equity [1]	5-Year Average Common Equity to Market Value Ratio [2]	Weighted - Average Cost of Preferred Equity [3]	5-Year Average Preferred Equity to Market Value Ratio [4]	Weighted Average Cost of Debt [5]	5-Year Average Debt to Market Value Ratio [6]	Northwestern's Income Tax Rate [7]	Overall After- Tax Cost of Capital [8]
Atmos Energy Corp		10.4%	0.56	-	-	6.0%	0.44	35.0%	7.5%
Laclede Group Inc/The	*	10.8%	0.59	5.9%	0.00	5.9%	0.41	35.0%	7.9%
Northwest Natural Gas Co	*	10.1%	0.61	5.8%	0.00	5.8%	0.39	35.0%	7.6%
Piedmont Natural Gas Co	*	10.4%	0.68	-	-	5.9%	0.32	35.0%	8.3%
South Jersey Industries Inc		9.7%	0.63	6.0%	0.00	6.1%	0.37	35.0%	7.6%
Southwest Gas Corp		10.8%	0.41	-	-	6.1%	0.59	35.0%	6.8%
WGL Holdings Inc	*	10.8%	0.66	5.8%	0.01	5.7%	0.33	35.0%	8.4%
AGL Resources Inc		11.5%	0.58	5.9%	0.02	5.9%	0.41	35.0%	8.2%
Vectren Corp		11.5%	0.59	5.9%	0.00	5.9%	0.41	35.0%	8.3%
Average		10.6%	0.59	5.9%	0.00	5.9%	0.41	35.0%	7.8%
Subsample Average		10.5%	0.63	5.8%	0.00	5.8%	0.36	35.0%	8.0%

Sources and Notes:
[1]: Table No. MJV-10; Panel B, [5].
[2]: Table No. MJV-4, [4].
[3]: Workpaper #2 to Table No. MJV-11 ; Panel B, [1].
[4]: Table No. MJV-4, [5].
[5]: Workpaper #2 to Table No. MJV-11 ; Panel A, [1].
[6]: Table No. MJV-4, [6].
[7]: Provided by Northwestern.
[8]: ([1] x [2]) + ([3] x [4]) + {[5] x [6] x (1 - [7])}.

*Represents companies in the subsample.

Table No. MJV-11

Overall Cost of Capital of the MJV US Gas LDC Sample

Panel F: ECAPM (2%) Cost of Equity Based on Value Line Betas and a Short-Term Risk-Free Rate

Company		ECAPM (2%) Cost of Equity [1]	5-Year Average Common Equity to Market Value Ratio [2]	Weighted - Average Cost of Preferred Equity [3]	5-Year Average Preferred Equity to Market Value Ratio [4]	Weighted Average Cost of Debt [5]	5-Year Average Debt to Market Value Ratio [6]	Northwestern's Income Tax Rate [7]	Overall After- Tax Cost of Capital [8]
Atmos Energy Corp		10.6%	0.56	-	-	6.0%	0.44	35.0%	7.6%
Laclede Group Inc/The	*	10.9%	0.59	5.9%	0.00	5.9%	0.41	35.0%	8.0%
Northwest Natural Gas Co	*	10.3%	0.61	5.8%	0.00	5.8%	0.39	35.0%	7.8%
Piedmont Natural Gas Co	*	10.6%	0.68	-	-	5.9%	0.32	35.0%	8.4%
South Jersey Industries Inc		10.0%	0.63	6.0%	0.00	6.1%	0.37	35.0%	7.8%
Southwest Gas Corp		10.9%	0.41	-	-	6.1%	0.59	35.0%	6.8%
WGL Holdings Inc	*	10.9%	0.66	5.8%	0.01	5.7%	0.33	35.0%	8.5%
AGL Resources Inc		11.5%	0.58	5.9%	0.02	5.9%	0.41	35.0%	8.3%
Vectren Corp		11.5%	0.59	5.9%	0.00	5.9%	0.41	35.0%	8.3%
Average		10.8%	0.59	5.9%	0.00	5.9%	0.41	35.0%	7.9%
Subsample Average		10.7%	0.63	5.8%	0.00	5.8%	0.36	35.0%	8.2%

Sources and Notes:
[1]: Table No. MJV-10; Panel B, [6].
[2]: Table No. MJV-4, [4].
[3]: Workpaper #2 to Table No. MJV-11 : Panel B, [1].
[4]: Table No. MJV-4, [5].
[5]: Workpaper #2 to Table No. MJV-11 ; Panel A, [1].
[6]: Table No. MJV-4, [6].
[7]: Provided by Northwestern.
[8]: ([1] x [2]) + ([3] x [4]) + {[5] x [6] x (1 - [7])}.

*Represents companies in the subsample.

Table No. MJV-11

Overall Cost of Capital of the MJV US Gas LDC Sample

Panel G: ECAPM (3%) Cost of Equity Based on Value Line Betas and a Short-Term Risk-Free Rate

Company		ECAPM (3%) Cost of Equity [1]	5-Year Average Common Equity to Market Value Ratio [2]	Weighted - Average Cost of Preferred Equity [3]	5-Year Average Preferred Equity to Market Value Ratio [4]	Weighted Average Cost of Debt [5]	5-Year Average Debt to Market Value Ratio [6]	Northwestern's Income Tax Rate [7]	Overall After- Tax Cost of Capital [8]
Atmos Energy Corp		10.8%	0.56	-	-	6.0%	0.44	35.0%	7.7%
Laclede Group Inc/The	*	11.1%	0.59	5.9%	0.00	5.9%	0.41	35.0%	8.1%
Northwest Natural Gas Co	*	10.6%	0.61	5.8%	0.00	5.8%	0.39	35.0%	7.9%
Piedmont Natural Gas Co	*	10.8%	0.68	-	-	5.9%	0.32	35.0%	8.5%
South Jersey Industries Inc		10.3%	0.63	6.0%	0.00	6.1%	0.37	35.0%	8.0%
Southwest Gas Corp		11.1%	0.41	-	-	6.1%	0.59	35.0%	6.9%
WGL Holdings Inc	*	11.1%	0.66	5.8%	0.01	5.7%	0.33	35.0%	8.6%
AGL Resources Inc		11.6%	0.58	5.9%	0.02	5.9%	0.41	35.0%	8.3%
Vectren Corp		11.6%	0.59	5.9%	0.00	5.9%	0.41	35.0%	8.4%
Average		11.0%	0.59	5.9%	0.00	5.9%	0.41	35.0%	8.0%
Subsample Average		10.9%	0.63	5.8%	0.00	5.8%	0.36	35.0%	8.3%

Sources and Notes:
[1]: Table No. MJV-10; Panel B, [7].
[2]: Table No. MJV-4, [4].
[3]: Workpaper #2 to Table No. MJV-11 : Panel B, [1].
[4]: Table No. MJV-4, [5].
[5]: Workpaper #2 to Table No. MJV-11 : Panel A, [1].
[6]: Table No. MJV-4, [6].
[7]: Provided by Northwestern.
[8]: ([1] x [2]) + ([3] x [4]) + {[5] x [6] x (1 - [7])}.

*Represents companies in the subsample.

Table No. MJV-12

Risk Positioning Cost of Equity at Northwestern's Capital Structure

MJV US Gas LDC Sample

Panel A: Using Value Line Betas

	Overall Cost of Capital [1]	Northwestern's Regulatory % Debt [2]	Northwestern's Cost of Debt [3]	Northwestern's Income Tax Rate [4]	Northwestern's Regulatory % Equity [5]	Estimated Return on Equity [6]
Using Long-Term Risk-Free Rates:						
CAPM using Value Line Betas	7.7%	0.49	6.1%	35.0%	0.51	11.1%
ECAPM (0.50%) using Value Line Betas	7.7%	0.49	6.1%	35.0%	0.51	11.2%
ECAPM (1.50) using Value Line Betas	7.8%	0.49	6.1%	35.0%	0.51	11.4%
Using Short-Term Risk-Free Rates:						
CAPM using Value Line Betas	7.7%	0.49	6.1%	35.0%	0.51	11.3%
ECAPM (1%) using Value Line Betas	7.8%	0.49	6.1%	35.0%	0.51	11.5%
ECAPM (2%) using Value Line Betas	7.9%	0.49	6.1%	35.0%	0.51	11.7%
ECAPM (3%) using Value Line Betas	8.0%	0.49	6.1%	35.0%	0.51	11.9%

Sources and Notes:
[1]: Table No. MJV-11; Panels A - G, [8].
[2]: Provided by Northwestern.
[3]: Based off an BBB rating, as provided by Northwestern. Yield pulled from Bloomberg as of March 27, 2007.
[4]: Provided by Northwestern.
[5]: Provided by Northwestern.
[6]: {[1] - ([2] x [3] x (1 - [4]))} / [5].

Table No. MJV-12

Risk Positioning Cost of Equity at Northwestern's Capital Structure

MJV US Gas LDC Sample

Panel B: Using Subsample and Value Line Betas

	Overall Cost of Capital [1]	Northwestern's Regulatory % Debt [2]	Northwestern's Cost of Debt [3]	Northwestern's Income Tax Rate [4]	Northwestern's Regulatory % Equity [5]	Estimated Return on Equity [6]
Using Long-Term Risk-Free Rates:						
CAPM using Value Line Betas	7.8%	0.49	6.1%	35.0%	0.51	11.5%
ECAPM (0.50%) using Value Line Betas	7.9%	0.49	6.1%	35.0%	0.51	11.6%
ECAPM (1.50) using Value Line Betas	8.0%	0.49	6.1%	35.0%	0.51	11.8%
Using Short-Term Risk-Free Rates:						
CAPM using Value Line Betas	7.9%	0.49	6.1%	35.0%	0.51	11.6%
ECAPM (1%) using Value Line Betas	8.0%	0.49	6.1%	35.0%	0.51	11.9%
ECAPM (2%) using Value Line Betas	8.2%	0.49	6.1%	35.0%	0.51	12.1%
ECAPM (3%) using Value Line Betas	8.3%	0.49	6.1%	35.0%	0.51	12.3%

Sources and Notes:

[1]: Table No. MJV-11; Panels A - G, [8].

[2]: Provided by Northwestern.

[3]: Based off an BBB rating, as provided by Northwestern. Yield pulled from Bloomberg as of March 27, 2007.

[4]: Provided by Northwestern.

[5]: Provided by Northwestern.

[6]: {[1] - ([2] x [3] x (1 - [4]))} / [5].

AFFIDAVIT

COMMONWEALTH OF MASSACHUSETTS)
) ss
COUNTY OF MIDDLESEX)

I, Michael J. Vilbert, being first duly sworn on oath, do depose and state that I have read this document and am familiar with the contents thereof and the same are true to the best of my knowledge and belief.

FURTHER THE AFFIANT SAYETH NOT.

Michael J. Vilbert

Michael J. Vilbert

Subscribed and sworn to before me this 26th day of April, 2007.

Notary Public in and for
The Commonwealth of Massachusetts

My Commission expires: November 15, 2007

MARJORIE J. FISCHER
Notary Public
Commonwealth of Massachusetts
My Commission Expires Nov 15, 2007

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF NEBRASKA

IN RE:	)	
	)	**Docket No. NG-___**
NORTHWESTERN CORPORATION	)	
d/b/a NorthWestern Energy	)	

PREFILED DIRECT TESTIMONY OF JEFFREY J. DECKER
ON BEHALF OF NORTHWESTERN ENERGY

Q. Please state your name and business address for the record.

A. Jeffrey J. Decker, 600 Market St W., Huron, South Dakota 57350.

Q. By whom are you employed and in what position?

A. I am employed by NorthWestern Energy as a Specialist Regulatory.

Q. Please describe your education and business experience and business credentials.

A. I graduated in 1986 from Dakota Wesleyan University with a Bachelor of Arts degree in Business Administration. I joined NorthWestern Public Service in 1988 as a corporate accountant working with financial reporting. Starting in 1993 I worked with NorthWestern Growth Corporation. My responsibilities included financial analysis of potential acquisitions. In 1995 I became the director of rates. I was promoted to Manager of Financial Services – NEC in 1998. In 2004 my title was changed to Specialist Regulatory for NorthWestern Energy.

Since 1996 I have been responsible for developing the NorthWestern Energy Gas revenue budgets for South Dakota and Nebraska. I also maintain and analyze heating degree day data for both states on a monthly basis.

Q. What is the purpose of your prepared direct testimony?

A. I am supporting the weather normalization pro forma adjustments and the Revenue Requirement and Cost of Service Study.

Revenue Requirements Study and Cost of Service Study

Q. Have you prepared any exhibits in support of your testimony?

A. Yes, I am sponsoring two exhibits related to my testimony in this case, Exhibit JJD-1 and Exhibit JJD-2. Various schedules are included as part of these exhibits, including the details of all the operating income statement and rate base adjustments. Exhibit JJD-1 sets forth the Nebraska Revenue Requirements study and Exhibit JJD-2 is the Nebraska jurisdiction class cost of service study.

Q. Were these exhibits prepared by you or under your direction and supervision?

A. Yes, they were. Certain pro forma adjustments to operating income are supported by other NorthWestern witnesses. I address those witnesses under the discussion of the pro forma.

Q. Do these exhibits reflect the information shown on NorthWestern's books and records for the corresponding base period?

A. Yes. The information shown per books, or actual, with the exception of the

Federal and State Income Taxes Line on Schedule 1 of Exhibit JJD-1, was taken from the books and records of NorthWestern for the base period consisting of the twelve-month period ended December 31, 2006. The Federal and State Income Taxes were calculated using a Federal rate of 35% and a State Income Tax Rate of 7.81%. The historical base period amounts were adjusted for known and measurable changes expected to occur during the time proposed rates go into effect.

Revenue Requirements Study

Q. What is contained in Exhibit JJD-1?

A. Exhibit JJD-1 is the Nebraska Gas Revenue Requirements study. A total of ten major schedules are contained in this exhibit.

Q. What is contained in Exhibit JJD-1, Schedule No. 1?

A. Schedule No. 1 of this exhibit is the Financial Summary, which sets forth the Nebraska Gas Operating Income Statement with Pro Forma Adjustments. This shows, on a summary basis:

1. The 2006 base year Nebraska Gas operating revenues and expenses as included on the Company's 2006 Books and Records (Column (c));
2. The pro forma adjustments needed to reflect known and measurable changes used to determine the level of revenues and expenses for ratemaking purposes (Column (d));
3. The adjusted and normalized base year operating income (Column (e));
4. The revenue adjustment required to have Adjusted Test Year Operating

Income match the requested return (Column (f)); and

5. The Nebraska Gas Operating Income Statement with the proposed revenue adjustment (Column (g)).

Q. Please explain what is contained on Exhibit JJD-1, Schedule No. 1.1.

A. Schedule No. 1.1, consisting of 3 pages, summarizes the individual pro forma adjustments to revenues and expenses, showing the effect on operating income of each of the adjustments made to the Company's books and records to arrive at the appropriate revenues and expenses for revenue requirements purposes.

Q. Please explain what is contained on Exhibit JJD-1, Schedule No. 1.2.

A. Schedule No. 1.2, consisting of 1 page, summarizes the individual pro forma adjustments to rate base. The schedule shows the effect on Nebraska gas rate base of each of the known and measurable pro forma adjustments made to the Company's books and records for purposes of arriving at the appropriate rate base for this ratemaking proceeding.

Q. Would you briefly summarize what is contained on the other schedules included as part of Exhibit JJD-1.

A. Schedule No. 2, consisting of 1 page, is a summary of gas sales and transportation revenues, containing actual base year billing units and revenues. Revenues have been broken down into type of revenue recovery, customer charges, distribution delivery charges, ad valorem tax adjustment clause and gas costs. In addition, test year billing units are shown with associated revenues derived using present and proposed rates.

Schedule No. 2.1, consisting of 7 pages, contains the weather normalization of billing unit results. Each page sets forth revenues at base year actual, present and proposed rates by rate schedule.

Schedule No. 2.2, consisting of 3 pages, contains the monthly heating degrees for Grand Island and North Platte, Nebraska.

Schedule No. 3, consisting of 1 page, sets forth the details of other revenues, by account, during the base period and two years prior to the base period.

Schedule No. 4, consisting of 3 pages, contains base period unadjusted and test period adjusted operations and maintenance expenses by account.

Schedule No. 5, consisting of 1 page, contains information on the Company's depreciation and amortization expense. This schedule also contains the allocation of common depreciation to Nebraska Gas.

Schedule No. 6, consisting of 1 page, shows the particulars on the Company's taxes other than income taxes expense.

Schedule No. 7, consisting of 1 page, shows the computation of income taxes.

Schedule No. 8, consisting of 1 page, sets forth the Company's estimate of rate case expense in this proceeding, along with the related adjustment to rate base for the unamortized rate case expense.

Schedule No. 9, consisting of 1 page, contains the computation of rate base and return.

Schedule No. 9.1, consisting of 2 pages, shows the book balances of plant accounts as of December 31, 2005 and 2006, along with base and test year adjusted thirteen-month average balances.

Schedule No. 9.2, consisting of 1 page, contains the consolidated capital structure of NorthWestern Corporation, and the computation of the cost of capital used in this docket. NorthWestern witness Evans sponsors information contained on this schedule.

Schedule No. 9.3, consisting of 4 pages, contains the calculation of the thirteen-month average balance for certain rate base items, including any allocation of common cost to Nebraska Gas.

Schedule No. 9.4, consisting of 1 page, contains the calculation of the thirteen-month average balance for accumulated depreciation and amortization expense.

Schedule No. 11, consisting of 1 page, sets forth the common or indirect allocation factors for the test period. These factors have been based on actual 12 months ended May 31, 2005 data, and were used to allocate common or indirect costs during 2006.

Pro Forma Adjustments – Operating Income Statement

Q. Mr. Decker, can you please refer back to Schedule No. 1.1 of Exhibit JJD-1? Would you please explain each individual pro forma adjustment to the operating income statement?

A. I will address adjustments 1, 2 and 17. Witness Kliewer has addressed the remaining adjustments in his testimony.

Adjustment No. 1 – Weather Normalization

Details and calculation of this adjustment are shown on Schedule Nos. 2.1 and 2.2. This adjustment decreases the revenue requirement by $673,767.

NorthWestern has made certain adjustments to base year volumes in determining test year volumes. The upward adjustment to base year volumes delivered to retail customers is primarily the result of warmer than normal weather in the base year. Heating degree-days during the base year were approximately 87 percent of normal, as shown on schedule 2.2. In summary, actual base year volumes were divided into temperature sensitive and non-temperature sensitive volumes. The non-temperature sensitive volume was determined using the August and September 2006 volumes in the base period. The temperature sensitive volume for the year was then calculated by subtracting the non-temperature sensitive volume from the total volume. The temperature sensitive volumes are normalized in a linear manner adjusting the base period temperature sensitive volumes by the ratio of historical normal heating degree days to the actual heating degree days matched to billing cycles during the twelve months ended December 31, 2006.

This adjustment also determines the gas supply cost adjustments using weather normalized sales requirements and the cost component of each rate schedule in effect on April 2, 2007. The April 2 Purchased Gas Cost rate used in this filing is lower than the 12-month average rate in effect during the 2006 test year. This results in the lower gas costs and revenue shown in adjustment No. 1.

Adjustment No. 2 – Other Revenues

Details and calculation of this adjustment are shown on Schedule No. 3. This adjustment increases the revenue requirement by $35,862.

This adjustment is made to derive a more representative level of test year miscellaneous gas service revenues, based on three-year average actual revenues for the period ending December 31, 2006.

Adjustment No. 17 – General Terms Proposed Changes

The detail of this adjustment is discussed in the General Terms and Conditions section of this testimony. This adjustment decreases the revenue requirement by $21,520.

Pro Forma Adjustments – Gas Rate Base

Q. Would you please explain each individual pro forma adjustment to rate base, summarized on Schedule No. 1.2 of Exhibit JJD-1.

A. ***Adjustment No. 1 – Rate Case Expense***

Details and calculation of this adjustment are shown on Schedule No. 8.

This adjustment increases rate base by $30,000 with an associated revenue requirement impact of $2,694 for return and associated income taxes.

This pro forma adjustment to rate base is the result of including in rate base the unamortized portion of rate case expense estimated in operating income statement Adjustment No. 3. This is consistent with prior ratemaking treatment.

Class Cost of Service Study

Q. What is the basis for the class cost of service study contained in Exhibit JJD-2?

A. The study is based on Nebraska jurisdictional operations for the 12-month period ended December 31, 2006, as adjusted for known and measurable changes. All of the operating income statement and rate base figures are taken directly from the detail included in the previously mentioned revenue requirements study.

Q. What is the purpose of a class cost of service study?

A. A class cost of service study is an allocation to each rate schedule or class of customer of all revenues and costs relative to the furnishing of the utility service, including the appropriate assignment of revenues, operations and maintenance expenses, depreciation and other cost elements.

Q. Would you briefly describe the steps involved in preparing a class cost of service study?

A. The utility plant, revenue and expense accounts are examined and, where possible, amounts are assigned directly to certain classes of service or customers, based upon details derived from the books and records of the utility or by special analyses and studies. Amounts not directly assigned are analyzed by functional responsibility and groupings of accounts, such as production and distribution, then are allocated on the basis of demand, energy use and the number of customers associated with the various functional responsibilities.

Q. How are classes defined for the purpose of your class cost of service study?

A. This class cost of service study shows cost allocated to three service classes. Service classes are residential (Rate No. 91 – Residential Gas Service); small commercial (Rate No. 92 – General Gas Service); and large commercial (Rate Nos. 94, 95, 96 and 97 for sales service). The class cost of service study assumes all service classes are firm, due to a continuing shift away from the sale of gas toward the transportation of gas. In the past, interruptible service was related to gas supply and pipeline constraints, not to the general capability of the distribution system.

Q. Please discuss the principal classification and allocations used in Exhibit JJD-2.

A. Pages 4 and 5 contain the development of the classification ratios of cost to either customer, demand or commodity, while the allocation ratios to customer class are shown on pages 6 and 7. Demand-related costs are those that relate to the utility's ability to meet and sustain the maximum gas flow required by customers. On NorthWestern's system, these days occur when it is extremely cold. Demand-related costs thus relate to the capacity that must be built into the system to meet peak operating conditions. Demand-related costs on NorthWestern's system include those associated with investments in peaking facilities and a substantial portion of distribution mains investment and related costs. In my study, I have classified 95 percent of distribution mains and 100 percent of peaking facilities as a demand-related cost. The demand-related costs are allocated on the basis of the use during a peak cold day in February, 2007.

Q. How were most of the other distribution costs allocated?

A. Costs associated with meters, services and regulators were allocated on the basis of the number of customers, weighted to account for differences in cost for the size of customer. In general, expenses were allocated on the basis of the plant to which they relate. Supervision and engineering expenses were allocated on the basis of the other related O&M accounts. Customer accounting expenses were allocated on the basis of weighted customers. Administrative and general costs, including common plant investment, were generally allocated in proportion to the allocation of distribution and production plant investment and expenses.

Q. What are the results of the class cost of service study?

A. The results are summarized on Pages 1 and 2 of the exhibit containing the study. Page 2 of the study shows, based on pro forma results at present rates, the following rates of return by class of customer:

Residential	2.17%
Small Commercial	2.67%
Large Commercial	3.90%

Shown on Page 1 of the study is the level of revenue requirement needed by each customer class to attain an overall rate of return requested by NorthWestern in this filing of 8.98%.

Q. What are the principle conclusions you reach from your study?

A. Based on results of this study, I find that existing gas revenues fail to cover Nebraska Gas jurisdictional revenue requirements by just over $2.8 million

Q. What are the revenue deficiency amounts by class of customer and the percentage increase in non-gas cost revenue required?

A.

Residential	$2,153,059	or 33.17% Increase
Small Commercial	491,429	or 38.39% Increase
Large Commercial	169,305	or 31.48% Increase
Total	$2,813,794	or 33.86% Increase

Rate Design and Proposed Rates

Q. Are you recommending a change to the current rate structure of NorthWestern's rate schedules?

A. No changes in rate structure are being recommended. The only changes being made are increases to the customer and non-gas cost delivery service charge component of rates.

Q. Please describe your proposed rate change for the residential class (Rate No. 91).

A. Overall proposed revenue increases for residential customers are consistent with revenue levels required in the class cost of service study. NorthWestern is proposing to increase its monthly customer charge for residential customers by \$3.00 to \$8.00. The class cost of service study indicates that a fully loaded customer charge for this type of account should be in the \$14 per month range. The remaining increase, not collected via the proposed customer charge increase, was included in the distribution delivery commodity charge. More of the increase was put into the first rate block, to compensate for the entire customer related costs not being collected in the monthly customer charge. It should be noted that the normalized therms used in the 1999 filing were 33,538,480. The normalized therms for this filing are 26,200,310. This mirrors the reduction in use per HDD factors that we note each year as customers install newer, more efficient furnaces, water heaters and appliances.

Q. Please describe your proposed rate change for the small commercial class (Rate No. 92 or General Gas Service).

A. Overall proposed revenue increases for small commercial customers are consistent with revenue levels required in the class cost of service study. NorthWestern is proposing to increase its monthly customer charge for small commercial customers by \$3.00 to \$9.00. The class cost of service study indicates that a fully loaded customer charge for this type of account should be in the \$16 per month range. The remaining increase, not collected via the proposed customer charge increase, was included in the distribution delivery commodity charge. More of the increase was put into the first rate block, to compensate for the entire customer related costs not being collected in the monthly customer charge.

Q. Please describe your proposed rate change for the large commercial class (Rate Nos. 94, 95, 96 and 98).

A. Again, overall proposed revenue increases for large commercial customers are consistent with revenue levels required in the class cost of service study. NorthWestern is proposing to maintain its current monthly customer charge for large commercial customers. The increase was included in the distribution delivery commodity charge.

Changes to the General Terms and Conditions

Q. Please explain the rate related changes made to NorthWestern's General Terms and Conditions as part of this filing.

A. NorthWestern has needed an update to its general terms and conditions in several areas.

Q. What changes are you making to the Customer Connection Charges?

A. Section 4, Sheet No. 1. The connection/reconnection charge for customers after hours service is currently $15.00 or based on the Company's hourly rates for service work with a one hour minimum in the instance of a reconnection. The actual cost of this service is significantly higher and the change in the tariff is made to align the cost with the actual expense to the Company. The increase in this charge is designed to encourage customers to have connections/reconnections accomplished during normal work hours and to more closely align the cost of the Company to provide the service with the charge made to the Customer.

Q. Are you changing the cost of the Customer Connection Charges during normal work hours?

A. No the cost of connection/reconnection during working hours will remain $10.00.

Q. Are you making any other changes to the Customer Connection Charges?

A. Yes. Also in Section 4, Sheet No. 1, you will note the addition of a seasonal use customer charge. This again is to more closely align the revenue from the service with the cost of providing the service. The seasonal customers normally require additional travel for both the connection and reconnection of their service. Since the customer must be turned off and on at least once each year, there is additional cost in serving the customer as compared to a customer that remains on the system for all twelve months. In instances such as grain dryers, the customer may only be connected for one to two months of the year. Swimming pools are often only connected for three to four months of the year. The company does not collect monthly base customer charges as the customer is not considered active while the gas is turned off.

Q. Can you describe the changes regarding residential customers related to Line Connection Costs in Section 4, Sheet 7?

A. NorthWestern's tariff currently allows for a charge of $90.00 for each new service connection.

Q. Why do you specify the contribution of $90 for customers with primary space

heating and a water heater verses the other appliances?

A. It is becoming more common for a customer to request the company to run a gas line for a fireplace or a water heater only. Since the use for these appliances is minimal, there is no chance for the Company to recover its investment. Although we enjoy adding customers to our system, it does not make sense to add a customer that will not pay their share of the total system costs. With this change customers in this category will cover their share of the costs of service.

Q. What if a customer requires more than 150 feet for their gas service. How will you determine the appropriate amount to charge the customer?

A. The company will compare the expected revenues to the expected cost to determine what, if any, additional contribution should be made by the customer.

Q. Have you considered the Commercial or Industrial Customer and their Line Extension Costs?

A. Yes we have. The Company will compare the cost of providing the Line Extension with the expected revenues. The result will determine what, if any contribution is required of the customer. This seeks to align the costs caused by the customer with the revenue from the same customer.

Q. In Section 4, Sheet No. 7, why have you included a section to consider the costs of a Line Extension outside of the Normal Construction Season?

A. Costs associated with working in frozen ground are higher than working in the normal construction season. The time for the service is increased, plus the wear and tear on equipment contributes to increased maintenance expense.

Q. What is the purpose of the grade language in Section 4, Sheet No. 7?

A. If a contractor requests the service to be installed and the grade is later altered, the service may then be too shallow or too deep. This results in either a code problem, an operational problem or both. This change would require the grade to be within six inches of final grade and would eliminate having to later correct a problem that could have been prevented.

Q. How will you determine the revenues to be used in the calculation?

A. As part of the tariff in Section 4, Sheet No. 7, the Company proposes a "true-up" that will hold both parties accountable to the original estimate. After three years the company can review the quantity of gas used by the customer, to determine that the gas used is in line with the original projection provided by the customer. If the usage varies by greater than 20%, the Company has the option to pursue an additional contribution or to pay back the excess contribution to the customer.

Q. Have you made any other monetary changes to the general terms and conditions?

A. Yes. In Section 4, Sheet No. 2, the company proposes an addition to the Access to Premises section. The customer billing system currently allows a bill to be estimated up to 3 consecutive times. Upon the fourth attempt, the system requires an actual meter read must be taken. In instances of locked gates, dogs, etc., the meter reader or service tech must make special arrangements with the customer in order to finally be allowed access to read the meter. This requires additional expense. This charge acts as an incentive for the customer to make arrangements so the meter reader can read the meter as part of their normal route.

Q. Are there additional changes in the general terms that will impact customers?

A. In Section 4, Sheet No. 1, the company proposes to add language stating that the Customer or their representative must be present at the time of service connection. This is to ensure the service technician knows what appliances need to be lit, in addition to any special circumstances that may be present at the location.

Q. Please discuss the new language regarding the tampering fee in Section 4, Sheet No. 2.

A. This language allows the company to bill for the natural gas used, damage to equipment and correcting of any meter tampering or bypass equipment. This changes gives the Company a tool to recover the costs associated with someone tampering with the Company's meters. The Company can pursue the recovery of the costs from the individual responsible without burdening the local legal system.

Q. What is the purpose for the changes made to the budget payment plan?

A. In May of 2006, NorthWestern received approval from the South Dakota Public Utilities Commission regarding the language change for the budget payment section of our electric tariff. In this filing we are proposing the same language for our Nebraska Tariff. This change does not represent an increase or decrease in cost to the customer.

Q. Does this complete your testimony?

A. Yes it does.

EXHIBITS JJD-1 and JJD-2

(Exhibits JJD-1 and JJD-2 and accompanying Schedules are being filed under separate cover as Confidential Exhibits and are subject to the Protective Order entered by the Nebraska Public Service Commission in this docket.)

AFFIDAVIT

STATE OF SOUTH DAKOTA)
) ss
COUNTY OF BEADLE)

I, Jeffrey Decker, being first duly sworn on oath, do depose and state that I have read this document and am familiar with the contents thereof and the same are true to the best of my knowledge and belief.

FURTHER THE AFFIANT SAYETH NOT.

Jeffrey Decker

Jeffrey Decker

Subscribed and sworn to before me this 30th day of April, 2007.

JoAnne H Peterson

Notary Public in and for the State of South Dakota

5/29/2010